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ADVANCED RESERVOIR CHARACTERIZATION IN THE ANTELOPE SHALE TO ESTABLISH THE VIABILITY OF CO2 ENHANCED OIL RECOVERY IN CALIFORNIA'S MONTEREY FORMATION SILICEOUS SHALES

Annual Report
February 12, 1996 - February 11, 1997

By
R. M. Toronyi

December 1997

Performed Under Contract No. DE-FC22-95BC14938

Chevron USA Production Company
Bakersfield, California

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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Advanced Reservoir Characterization In The Antelope Shale To Establish The Viability Of CO2 Enhanced Oil Recovery In California's Monterey Formation Siliceous Shales

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Abstract

The Buena Vista Hills field is located about 25 miles southwest of Bakersfield, in Kern County, California, about two miles north of the city of Taft, and five miles south of the Elk Hills field. The Antelope Shale zone was discovered at the Buena Vista Hills field in 1952, and has since been under primary production. Little research was done to improve the completion techniques during the development phase in the 1950s, so most of the wells are completed with about 1000 ft of slotted liner. The proposed pilot consists of four existing producers on 20 acre spacing with a new 10 acre infill well drilled as the pilot CO_2 injector. Most of the reservoir characterization of the first phase of the project will be performed using data collected in the pilot pattern wells.

This is the first annual report of the project. It covers the period February 12, 1996 to February 11, 1997. During this period the Chevron Murvale 653Z-26B well was drilled in Section 26-T31S/R23E in the Buena Vista Hills field, Kern County, California. The Monterey Formation equivalent Brown and Antelope Shales were continuously cored, the zone was logged with several different kinds of wireline logs, and the well was cased to a total depth of 4907 ft. Core recovery was 99.5%. Core analyses that have been performed include Dean Stark porosity, permeability and fluid saturations, field wettability, anelastic strain recovery, spectral core gamma, profile permeametry, and photographic imaging. Wireline log analysis includes mineral-based error minimization (ELAN), NMR T2 processing, and dipole shear wave anisotropy. A shear wave vertical seismic profile was acquired after casing was set and processing is nearly complete.

Executive Summary

Monterey Formation siliceous shale in California represents a major but largely underdeveloped domestic oil resource. Monterey Formation siliceous shale in the San Joaquin Valley, locally called the Antelope Shale, contains an estimated 7 billion barrels of oil in place (OIP). The Monterey Shale that underlies much of California's coastal area and offshore holds nearly 3 billion barrels. Thus, the focus of this project is the 10 billion barrel (OIP) fractured siliceous shale resource.

Siliceous shale is an unusual reservoir for hydrocarbons, both because it is found in only a few hydrocarbon basins in the world and its production characteristics are unlike any other type of reservoir rock. It is composed primarily of diagenetically altered biogenic silica. It has relatively high porosity but very low permeability that must be naturally or artificially fractured to produce oil at economic rates.

This project represents the first comprehensive characterization of siliceous shale in the San Joaquin basin in the public domain using advanced coring, logging, fracture characterization and modeling. It is also potentially the first CO_2 EOR flood conducted in the siliceous shale, and it is the first project to integrate advanced seismic and other injection profiling tools to monitor fluid flow through this fractured reservoir.

Project Objectives

The primary objective of this project is to increase oil recovery from the Monterey/Antelope siliceous shale. The project goals are to 1) fully characterize the reservoir storage, flow paths and other key properties of the Antelope Shale zone, 2) design and pilot test the optimum CO_2 EOR flood for the Antelope Shale to achieve good sweep efficiency, and 3) transfer the reservoir characterization and EOR technology to other Antelope Shale zone producers.

The research consists of four primary work processes: Reservoir Matrix and Fluid Characterization; Fracture Characterization; Reservoir Modeling and Simulation; and CO_2 Pilot Flood and Evaluation. The first phase of the project will focus on the application of a variety of advanced reservoir characterization techniques to determine the production characteristics of the Antelope Shale reservoir. Reservoir models based on the results of the characterization work will be used to evaluate how the reservoir will respond to secondary recovery and EOR processes. The second phase of the project will focus on implementation and evaluation of an advanced enhanced oil recovery (EOR) pilot.

Reservoir History

The Antelope Shale zone was discovered at the Buena Vista Hills field in 1952, and has been under primary production for the last 45 years. Since discovery 161 wells have been drilled through the Antelope Shale. The Antelope Shale zone was unitized in the East Dome area in 1954 and is currently operated by Texaco. Of the 52 wells in the West Dome part of the field, 20 are currently producing, 31 are shut-in, and 1 is abandoned. Average per well production is about 20 BOEPD, boosted recently from a low of 6 BOEPD. Average reservoir pressure is about 650 psi (-3400 ft VSS datum). Oil gravity ranges from 25° to 40° API, but averages about 30° API in the pilot area. The gross pay interval averages about 800 ft. Recovery to date has been about 9 MMB. With the estimated 130 MMB of original oil in place, 93% of the oil in West Dome is still trapped in the reservoir.

Geology

Structure, Stratigraphy, and Lithology

The Buena Vista Hills structure is an elongated doubly-plunging anticline with a northwest-southeast trend containing two structural culminations, referred to as East Dome and West Dome. The reservoir consists primarily of Upper Miocene fractured siliceous shale belonging to the Monterey Formation, locally known as the Brown Shale, Upper Antelope Shale, and Lower Antelope Shale.

The reservoir consists of up to 1325 ft of hard, brownish gray to gray siliceous. The Antelope Shale, of late Miocene age, extends from the Top Miocene Cherts (TMC) marker just above N point to P4 Point. The upper 350-500 ft, from TMC to P Point is essentially gas productive. The best oil production comes from the Pa to P2a zone. Below P Point, there are many thin sand laminae. Sand thicknesses usually range from 1mm to 25 cm. Sand represents about 4% of the reservoir thickness from TMC to P2 and about 6% from P to P2.

Fracturing

The fracture system is not believed to be pervasive because of the low average permeability of 0.64 md calculated from pressure build-up analyses, small drainage radii of 76 to 554 ft calculated from the pressure build-ups, and the unfractured nature of the bulk of the core. Core recoveries in BV are typically over 95%; the core in this study recovered 99.5% of the cored interval. However, there is ample evidence of significant fracture permeability in Buena Vista Hills field. Fracturing occurs at all scales from coffee-ground-like fractured rock, to rubble, to fractures spaced about every six feet. Fractures are mostly concentrated in carbonate beds.

Current Work Progress

Reservoir Matrix and Fluid Characterization

Production Logging (Task A.1.A.)

A downhole video log was run successfully on one pilot producer. Oil and water entry were observed in 554-26B in the air-filled part of the borehole during both shut-in and flowing periods. Gas entry was observed in the air-filled part of the borehole during flowing conditions only and in the fluid filled part of the borehole during both shut-in and flowing conditions. Oil entry was concentrated in a 25 ft thick zone just below P point, although evidence for oil entry near the bottom of the well was observed. Significant crossflow appears to occur during shut-in. Gas apparently flows out of deeper parts of the reservoir and into lower pressure zones and water flows from shallower and maybe deeper parts of the reservoir and into lower pressure zones. Gas and fluid exit points into the formation are unknown. Conventional production logs will have to be run to determine flow rates and exact water and gas entry points.

Core Analysis

The Chevron Murvale 653Z-26B well was spudded on July 1, 1996. The well was cored continuously through the Brown and Antelope Shales with the well deviated from vertical 20° west. A total of 32 cores were cut from 3955 to 4907 ft. Over this interval of interval of 952.8 ft, 948.1 ft of core was recovered.

Field Wettability Measurements (Task A.3.A.)

Wettability appears to be neither strongly water or oil wet for the most part, although some samples exhibited slight oil wet behavior and some water wet behavior. Sandstone laminae (basal thin sands in 2-3 in graded beds) typically appear water wet. The samples were consistently water wet below 4570 ft.

Anelastic Strain Recovery (Task A.3.B.)

Strain relaxation data were obtained on 10 samples: four in the Brown Shale, three in the upper Upper Antelope, and three in the lower Upper Antelope.. Interpretation by TerraTek suggests that the maximum principal stress axis is aligned approximately N40°E.

Laboratory Wettability Testing (Task A.3.B.)

Ten samples were chosen for wettability testing. All samples are still cleaning at this time and one sample has been eliminated from measurement consideration due to the inability to flow fluids through the sample in a reasonable time frame. Miscible cleaning is required to prepare the sample for testing without altering the pore geometry of the sample.

Spectral Core Gamma Scan (Task A.3.C.)

The spectral core gamma scan was performed on all core material to determine potassium, uranium and thorium concentrations in the core material. In addition, bulk density index, total gamma values and uranium-free gamma values were measured.

Detailed Core Description (Task A.3.E.)

Preliminary observations have shown that the Brown Shale interval contains almost no sand beds and appears to be quite siliceous. The first sand bed is just above P point and sand beds are quite common throughout the rest of the Antelope. Permeable appearing sand beds are commonly about 1 to 2 cm thick. A total sand thickness of about 35 ft was counted in the Antelope Shale.

Porosity, Permeability, and Fluid Saturations (Task A.3.F.)

One-inch diameter plugs were drilled every foot for porosity, permeability and saturation analysis (PK&S).

Of the preliminary analysis of PKS data, the most interesting aspects relate to matrix density variation and mini-permeameter data. The matrix density data is approximately linear with depth reflecting a change in character of Opal-CT with depth. This change affects the estimation of porosity from density and possibly neutron logs. The change can be due to a contraction of lattice dimensions, decrease in externally bound water, increase in authigenic quartz, or a combination of all.

Another interesting aspect of the PKS data is an apparent discrepancy between plug air permeability and profile permeameter results. The overall ratio is about 10:1 (profile perm to PKS). The PKS results fail to support local increases in permeability indicated by profile permeameter.

Profile Permeametry (Task A.3.N.)

The 1/3 slab section of the conventional core material was analyzed at a rate of 20 measurements per foot using Core Laboratories' Pressure Decay Profile Permeameter (PDPK™).

Core Photography and Core Imaging (Task A.3.O.)

Composite photography in white light and ultraviolet light was completed. Using Core Laboratories' Imagelog™ software, the ultraviolet images have been converted into binary images with the pay intervals being integrated to determine net pay in the cored interval..

Wireline Log Analysis (Task A.2.B and A.5)

The siliceous shale of Buena Vista Hills field challenges standard traditional wireline log interpretations. The formation matrix density is lower than that normally encountered in sands, which skews the porosity derived from logs when the matrix density is set to 2.65 g/cc, a standard for sandstone environments. The higher formation porosity also causes challenges for compensated neutron log porosity algorithms. The neutron porosity reads lower than true porosity.

Formation acoustic transit times are slow compared to many common siliciclastic rocks. Buena Vista Hills Antelope Shale appears to have less acoustic attenuation than many other areas of siliceous shale seen in the region. Shear wave slowness in this rock is moderate, ranging from 180 - 280 microseconds per ft.

Magnetic resonance of the formation appears to be a valuable tool for indication of rock parameters such as porosity, bound fluid, hydrocarbon typing, permeability, and residual oil saturation. These measurements used in conjunction with the other open hole data give a good analysis through zones of varying lithology and lamination thickness. The correlation of core porosity to CMR porosity tends to be quite good over the majority of the well. Residual oil saturation calculated using standard cutoffs on the T2 distributions is similar to core oil saturation.

Fracture Characterization

Shear-Wave Birefringence VSP (Task A.4.A)

A multicomponent vertical seismic profile (VSP) survey was recorded in well 653Z-26B, primarily for the purpose of evaluating stress and fracture effects as a function of depth. Data on field records appeared to be of outstanding quality. Birefringence analysis was expected to be completed during the 1st quarter of 1997 with P-wave and S-wave reflection imaging to follow shortly thereafter.

Cross-well Seismic Acquisition and Processing (Task A.4.B)

Tomoseis conducted a crosswell seismic field test between two producers in the pilot area that showed the existing slotted-liner wells were too noisy for hydrophones to record useable data due to the presence of gas-bubbles in the fluid column. Tomoseis now plans to conduct a field trial of their piezoelectric source tool in the pilot area in early February 1997 by placing their receivers in the unperforated new cored well, 653Z-26B.

Borehole Imaging Analysis (Task A.4.C)

Schlumberger completed an analysis of the FMI data from well 653Z during the fall of 1996. Bedding dips average 10.9° with an average dip azimuth of N34°E. Fracture dip azimuths vary between S40°E to S45°E. Fracture dips range from 10° to 90°, but the most common occurrence is between 80° and 90°. Fault dip azimuths vary from S40°E to S45°E direction. Dips range from 10° to 80° with only a slight preference for the 50° to 70° degree dip range.

High Resolution Structural Mapping (Task A.4.D)

Approximately 200 wells have been loaded to the database with another 20 more to be loaded shortly thereafter. A total of 7 Brown Shale and 15 Antelope marker tops are being correlated. Completion of the correlations, fault interpretations, and structure maps is expected in early 1997.

Outcrop Study (Task A.4.G.)

The outcrop study has been completed as scheduled. The study includes: field work in Chico Martinez Creek and along the coastal central California, reinterpretation of borehole images and well logs from several wells in Buena Vista Hills and other Antelope Shale fields nearby. The most significant results of this work are the following: brecciated faults and connected open fractures are major hydrocarbon pathways in the Monterey Formation. These structures control hydrocarbon migration and perhaps a large volume of production.

Regional Tectonic Synthesis (Task A.4.H)

Based on recent literature, it is now purported that the "weak" (i.e. zone of low friction) San Andreas fault system accommodates all of the strike-slip displacement and that the folds near the system are a result of the regional state of compression.. Stress state studies have shown that the direction of maximum horizontal compression is perpendicular to the San Andreas fault. With some fold axes oriented almost parallel to the San Andreas fault, it is now considered that fault-fold relationships consistent with thrust-fold belts are more appropriate in understanding the folds along the San Andreas fault system.

Faulting may control hydrocarbon migration and production in the Buena Vista Hills and surrounding fields especially where the faults evolve from a preexisting discontinuity and form a highly fractured or brecciated zone. These types of bed-parallel (and bed-perpendicular) faults have been observed and well documented throughout the Monterey Formation. The overall configuration of folds and faults in the Monterey indicates extensive crustal shortening (compression) of between 12 and 17 percent in a N30-40E direction.

Reservoir Modeling and Simulation

None of the tasks under this process have been completed.

CO2 Pilot Flood and Evaluation

None of the tasks under this process have been completed, except for profile permeametry, already described under Reservoir Matrix and Fluid Characterization.

Introduction

Siliceous shale is an unusual reservoir for hydrocarbons, both because it is found in only a few hydrocarbon basins in the world and its production characteristics are unlike any other type of reservoir rock. It is composed of the diagenetically altered silica shells of ancient diatoms, a planktonic plant that thrived in the coastal waters of western North America in the Miocene epoch. It has relatively high porosity but very low permeability reservoir rock that must be naturally or artificially fractured to produce oil at economic rates.

The Monterey Formation siliceous shale in California represents a major but largely underdeveloped domestic oil resource. The part of the Monterey Formation in the San Joaquin Valley, locally called the Antelope Shale, contains an estimated 7 billion barrels of oil in place (Chevron, 1994). The Monterey Shale that underlies much of California's coastal area and offshore holds nearly 3 billion barrels. Monterey Formation diatomite (i.e., Belridge Diatomite), a geologically and depositionally related siliceous sedimentary rock is not included in these resource estimates because it presents distinctly different production challenges. Thus, the focus of this project is the 10 billion barrel (OOIP) fractured siliceous shale resource. Particular emphasis is placed on the lower permeability, larger resource located in the San Joaquin Valley, specifically in the Buena Vista Hills, Elk Hills, Lost Hills, Asphalto, Midway Sunset, Railroad Gap, and other smaller fields (Figure 1).

The Need For and Importance of This Project

The operation of a Class III research and field demonstration project on the Antelope Shale is most timely. The wells in the Antelope Shale in many fields in the southern San Joaquin Valley have been declining for decades and are in danger of being abandoned. The recent well stimulation efforts by Chevron at Buena Vista Hills have "bought some time" for the Antelope Shale to be shown as a candidate for improved recovery and future commercial development.

This project represents the first comprehensive characterization of siliceous shale in the San Joaquin basin in the public domain using advanced coring, logging, fracture characterization and modeling. It is also the first CO_2 EOR flood conducted in the siliceous shale, and it is the first project to integrate advanced seismic and other injection profiling tools to monitor fluid flow through this fractured reservoir. As important, should the project demonstrate commercial viability, it may open up California light oils to CO_2 based EOR. Currently, sufficient CO_2 can be obtained from Chevron's gas plants for 5 MMCFGD of CO_2 supply. While additional CO_2 may be obtained from other gas plants and from additional industrial sources, the large scale application of this process will call for pipeline based CO_2 from the Rockies and the San Juan Basin. While these sources are nearly as close as California as to West Texas oil fields currently being flooded with CO_2, the major hurdle is to demonstrate a sufficiently large, economic use for the CO_2 in the California basins to justify the dedication of current pipeline capacity for low cost transmission of CO_2.

California producers involved with Monterey/ Antelope Shale production range from large majors (Chevron, Phillips, Texaco and Union) to small independents (Crimson Resources, Ferguson and Dole Enterprises). The largest "stakeholder" of the Antelope Shale resource, is DOE's Naval Petroleum Reserve at Elk Hills. A preliminary estimate, using data provided by Elk Hills/NPR, is that the siliceous shales underneath Elk Hills field contain on the order of 4 billion barrels of oil in place. The reservoir characterization and EOR pilot testing at Buena Vista will go far toward assisting the larger group of California Monterey/Antelope Shale producers as well as Elk Hills/NPR#1 to examine alternatives for increasing oil recovery from this large, underdeveloped resource.

Scope of Project

The overall scope of the project is to use advanced reservoir characterization on the Brown and Antelope Shales (Monterey Formation equivalent) in one newly drilled and cored well in the West Dome area of the Buena Vista Hills field. After characterizing the formation and determining the most appropriate enhanced oil recovery technique, a pilot demonstration enhanced oil recovery project will be installed using the four surrounding wells as producers and the newly drilled well as an injector.

The first step is to apply a variety of advanced reservoir characterization techniques to determine the reservoir and production characteristics of the Monterey Formation. These characteristics will be determined by innovative core and log analyses, laboratory core floods, and well tests, which will be used to build a reservoir model to simulate how the reservoir will respond to the application of advanced secondary recovery and EOR processes. The second step will be to design and implement an advanced EOR pilot demonstration in the West Dome part of the field to evaluate how effective the process is in increasing the recovery of oil.

The West Dome area of the Buena Vista Hills field is an excellent site for this reservoir characterization and EOR pilot project. The field has many features common not only to California siliceous shale reservoirs but many slope basin clastic reservoirs: it has been under primary production for a long time, the reservoir pressure is low, there is a long interval of pay, slotted liner completions are common, and oil recovery has been low.

Advanced Methods of Reservoir Characterization

Despite Chevron's numerous attempts to diagnose the Antelope Shale zone in Buena Vista Hills in the 1960s, little is known about the production characteristics of siliceous shale. Siliceous shale is not a typical clastic reservoir: it is thinly laminated, has tiny pore throats, low permeability, little clay, and is fractured. Little modern reservoir characterization information is available in West Dome because only 3 new wells have been drilled there since 1966. Advanced reservoir characterization tools need to be applied to understand the reservoir rock, its storage and flow paths, and its production mechanisms.

The reservoir characterization proposed here will be the first truly comprehensive modern reservoir characterization in the public domain performed on Monterey siliceous shale in the

San Joaquin Valley. It is designed to address the producibility problems mentioned below. Each analytical tool has a purpose and will answer one or more questions about how the reservoir produces oil and gas and how it would react to enhanced recovery processes. The advanced reservoir characterization techniques planned will be coordinated within the four main work processes: Reservoir Matrix and Fluid Characterization; Fracture Characterization; Reservoir Modeling and Simulation; and CO_2 Pilot Flood and Evaluation (Figure 2).

Project Objectives

The objectives of this project for increasing oil recovery from the Monterey/Antelope siliceous shale are threefold:

1. To fully characterize the reservoir storage, flow paths and other key properties of the Antelope Shale zone that control current oil recovery and that impact the success of the proposed EOR technique.

2. To design and pilot test the optimum EOR recovery process for the Antelope Shale to achieve good sweep efficiency in a fractured reservoir setting and favorable oil displacement from small pore throat rock.

3. To transfer the reservoir characterization and EOR technology to other Antelope Shale zone producers, and to other such properties held by Chevron as well as to the major Antelope Shale oil resources at Elk Hills.

Stratigraphic Nomenclature.

Chevron's common usage for Upper Miocene stratigraphy is somewhat different than the usage in the TORIS database and the literature. The Antelope Shale as defined by the Antelope Shale Zone Unit (ASZU) in East Dome, Buena Vista Hills field, and Graham and Williams (1985) is from Top Miocene Cherts (Tmc) to P4 Point (see Figure 3). Graham and Williams (1985) referred to the Antelope Shale as the upper unit of the McLure Member of the Monterey Formation (see Figure 4). Chevron's common usage distinguishes the interval between Tmc or N Point and P Point as the Brown Shale, and the interval between P Point and P4 Point as the Antelope Shale. Brown Shale is equivalent to the "N Shales" at Elk Hills. We find that the term Brown Shale is useful to distinguish the production characteristics of the interval above P from the interval below P Point, so it will be used throughout this report. Upper Antelope refers to the interval from P Point to P2a Point, and Lower Antelope the interval from P2a Point to P4 Point. The term "Antelope Shale zone" refers to the Brown and Upper and Lower Antelope Shale.

Reservoir History

The Antelope Shale zone was discovered at the Buena Vista Hills field in 1952, and has been under primary production for the last 45 years. Since discovery 161 wells have been drilled through the Antelope Shale. The Antelope Shale zone was unitized in the East Dome area in 1954 and is currently operated by Texaco. Of the 52 wells in the West Dome part of the field, 20 are currently producing, 31 are shut-in, and 1 is abandoned. Average per well production is about 20 BOEPD, boosted recently from a low of 6 BOEPD. Average reservoir pressure is about 650 psi (-3400 ft VSS datum). Oil gravity ranges from 25° to 40° API, but averages about 30° API in the pilot area. The gross pay interval averages about 800 ft. Recovery to date has been about 9 MMB. With the estimated 130 MMB of original oil in place, 93% of the oil in West Dome is still trapped in the reservoir.

Producibility Problems

The Antelope Siliceous Shale at the Buena Vista Hills field suffers from three primary problems that cause low recovery, current low production, and hamper any secondary recovery attempts. These producibility problems are common to all other siliceous shale reservoirs, with the exception of problem #1 (low pressure), since undeveloped siliceous shale reservoirs usually have high initial reservoir pressure. The three producibility problems are listed below:

1. The reservoir has low pressure (650 psi), low permeability (0.08 md), and the primary recovery mechanism is solution gas drive. At Buena Vista Hills, the reservoir pressure decreased rapidly until it was below bubble point after only 6 years of production. These factors combine to cause low recovery (currently 6.5% OOIP). We need to be able to displace oil from small pores and add energy to the reservoir to increase recovery.

2. Siliceous shale is a poorly understood reservoir because of complex lithology, unknown fracture patterns, low permeability matrix, interbedded sand laminae, and unknown formation damage. It is unknown how to determine "sweet spots" from log or core data for limited interval completion. It is also unknown how fractures or formation damage affect current production, although acid stimulation can improve productivity. The technology challenge is to develop a working reservoir model that will enable producers to drill, complete, and stimulate wells to maximize production at the lowest cost.

3. Inadequate reservoir characterization has led to limited ability to manage the siliceous shale reservoir, as a result, many mature siliceous shale fields are considered "stripper" properties, ready for abandonment. Because the siliceous shale is still so poorly understood, the current depletion strategy is often only a variation of "harvest the investment" strategy, where operators stop spending any money on siliceous shale wells. In addition, operators of properties that have siliceous shale are often hesitant to fully develop this asset because of geologic and technical uncertainties resulting from inadequate reservoir characterization.

Geology

Structure, Stratigraphy, and Lithology

The Buena Vista Hills structure is an elongated doubly-plunging anticline with a northwest-southeast trend containing two structural culminations, referred to as East Dome and West Dome (Figure 5). The crests of the two domes are 3.5 miles apart, with East Dome 240 ft structurally higher than West Dome. The pilot area is located just north of the crest of the anticline in Section 26B (Figure 6). The Antelope Shale Zone, as defined by the Antelope Shale Zone Unit, extends from the Tmc marker to P4 Point. The reservoir consists primarily of Upper Miocene fractured siliceous shale belonging to the Monterey Formation, locally known as the Brown Shale, Upper Antelope Shale, and Lower Antelope Shale (see Figure 3). Thin (1/2 to 25 cm) interbedded turbidite sands are common in the Antelope, representing up to 4% of the reservoir volume. The lateral stratigraphic continuity across the Buena Vista Hills field is legendary where channel turbidite sands are not present.

The reservoir consists of up to 1325 ft of hard, brownish gray to gray siliceous shale (see Figure 7). Figure 3 shows a log from the 653Z-26B and stratigraphic markers. The Antelope Shale, of late Miocene age, extends from the Top Miocene Cherts (TMC) marker just above N point to P4 Point. The upper 350-500 ft, from TMC to P Point is essentially gas productive. The best oil production comes from the Pa to P2a zone. Below P Point, there are many thin sand laminae. Sand thicknesses usually range from 1mm to 25 cm. Sand represents about 4% of the reservoir thickness from TMC to P2 and about 6% from P to P2.

A detailed examination of the 653Z-26B, 522A-26B, and 621-25B core has revealed that the Antelope Shale reservoir consists primarily of a stack of thin (1-5 cm) graded beds of siliceous shale with intercalated discrete sand beds . Each siliceous shale bed grades upward from sand, silt, or silty siliceous shale at the base to porcelanite at the top. A hemipelagic bed of very finely laminated siliceous shale or porcelanite caps the graded bed in places. The basal contact of each graded bed is commonly eroded. These observations and the published depositional environment for contemporaneous Stevens sand (e.g., Graham and Williams, 1985; Webb, 1981) has led us to the following depositional environment model.

Depositional Model

In the late Miocene epoch, submarine channels were common on the southwest side of the Maricopa depocenter (Webb, 1981). Many of the channels were fed with sand derived from Gabilan Range granitic rock on the southwest side of the San Andreas fault. At that time, the Gabilan Range was about 150 miles south of its present location near the town of Salinas. The submarine channels were the path that turbidity currents followed to carry material from the coastal shelf to the basin floor. The coarsest material was deposited in channels on submarine fans, which formed the Stevens turbidite sands (see Figure 8). The channels were located primarily in the low spots between submarine highs present at the time. The submarine highs were the surface expression of anticlines actively forming in the basin due to tectonic stress localized along the San Andreas fault. The anticlines continued to grow throughout the Pliocene, later becoming anticlinal oil fields like the Buena Vista Hills and the 29R and main structures at Elk Hills.

The basin was restricted, so tidal and storm currents were at a minimum, and much of the detritus from surrounding land areas was trapped on nearshore shelves (Graham and Williams, 1985). The water apparently was nutrient-rich, providing an ideal environment for diatom growth, so siliceous diatoms tests were constantly being deposited throughout the southwest part of the basin. The lack of clay and the abundance of biogenic silica within and between the Stevens sand turbidites suggests that the fine material in the sediment that allowed the turbidity currents to form was mostly diatoms.

Turbidity currents periodically swept down the channels, depositing sand in the submarine fans. The fine material in the turbidity current consisting of diatoms, very fine sand, silt, and clay was injected into the water column above the current. This fine detritus eventually settled out of suspension in the basin near the channels, forming siliceous graded beds. Subsequent turbidity currents eroded the siliceous graded beds that were deposited in the channels, leaving them preserved primarily on the submarine highs. Only very infrequently was sand deposited on the submarine highs when a channel formed near their base or an exceptionally large turbidity current occurred. The Antelope Shale built up over time as a thick sequence of these thin graded siliceous distal turbidite beds interbedded with hemipelagic siliceous deposits. Most of the anticlinal submarine highs were within the oxygen-minimum zone, which discouraged bioturbation and preserved the bedding and organic material (Graham and Williams, 1985).

Fracturing

The fracture system is not believed to be pervasive because of the low average permeability of 0.64 md calculated from pressure build-up analyses, small drainage radii of 76 to 554 ft calculated from the pressure build-ups, and the unfractured nature of the bulk of the core. Core recoveries in BV are typically over 95%, the core in this study recovered 99.5% of the cored interval. In contrast, core recoveries in the Point Arguello field in Monterey Formation offshore California were less than 5% in the highly fractured part of the reservoir. However, there is ample evidence of significant fracture permeability in Buena Vista Hills field.

For example, well 555-6D was acidized in 1957 and subsequently wells 505-5D, 551-7D, and 501-8D showed an abrupt increase in oil production. Well 544-26B was drilled in 1957 and lost circulation in the Antelope. Six days later, drilling mud was produced in wells 523-26B (2150 ft away), 543-26B (800 ft away), 553-26B (1130 ft away), 564-26B (1600 ft away), 566-26B (2400 ft away), and 556-26B (1900 ft away), skipping wells 554-26B and 555-26B. Fracturing occurs at all scales from coffee-ground-like fractured rock, to rubble, to fractures spaced about every six feet. Most of the fractures observed in core and microresistivity images are concentrated in carbonate beds.

Small scale "fractures" related to diagenesis are evident in core throughout the Brown and Antelope Shales. Williams (1982) described similar features as fluid escape fractures, which were formed when the sediment was compacting. They are typically 1 to 2 cm long, less than

1/2 mm thick, filled with material from adjacent beds, and parallel to each other. They are aligned parallel to the field's structural fold axis. Core analysis in well 621-25B has found that the rock matrix is 10 times more permeable parallel to these fractures than perpendicular to them (Chevron, 1994).

Current Work Progress

This section describes the work to date performed by Chevron and its technical partners under the DOE contract. Most of the data interpreted here has been collected on the newly drilled well Chevron Murvale 653Z-26B in Section 26-T31S/R23E (MDB&M) in the Buena Vista Hills field, Kern County, California.

Reservoir Matrix and Fluid Characterization

Most of the work performed during the early part of the first budget period of the project is characterizing the reservoir rock, fractures, and fluids.

Production Logging (Task A.1.A.)

Production logging to date has been limited to video logs. The logs have proved invaluable for planning further conventional production logging and crosswell seismic profiling.

Downhole video logs were run on wells 553-26B and 554-26B on 10/11/95 in order to determine exactly where oil, gas, and water are produced from the Antelope Shale. Downhole video logs were used to determine fluid entry because the wells are produced on pump and there was not enough room to run conventional production logs in the annulus between tubing and the slotted liner. Oil and water entry were observed in 554-26B in the air-filled part of the borehole during both shut-in and flowing periods. Gas entry was observed in the air-filled part of the borehole during flowing conditions only and in the fluid filled part of the borehole during both shut-in and flowing conditions. Oil entry was concentrated in a 25 ft thick zone just below P point, although evidence for oil entry near the bottom of the well was observed. The shut-in fluid level was found at mid perf level and was static. Gas bubbles and suspended solids obscured vision in the fluid-filled part of the borehole.

This evidence suggests that significant crossflow occurs during shut-in. Gas apparently flows out of deeper parts of the reservoir and into lower pressure zones and water flows from shallower and maybe deeper parts of the reservoir and into lower pressure zones. Gas and fluid exit points into the formation are unknown. Conventional production logs will have to be run to determine flow rates and exact water and gas entry points.

The fluid level in the 553-26B was above the slotted liner, so effective reservoir fluid entry could not be observed. A shallow casing leak with water entry and several holes in the casing were observed, which probably accounts for the high fluid level.

Wellsite Operations

The Chevron Murvale 653Z-26B well was spudded on July 1, 1996 by the Cleveland #2 drilling rig. A 20 in. conductor casing was previously set at 71 ft. A 17-1/2 in. hole was drilled to 801 ft and 13-3/8 in. casing was cemented to surface. Next a 12-1/4 in. hole was drilled to 3940 ft and 9-5/8 in. casing was cemented to surface. Horizon Well Logging mudloggers were installed at 1000 ft and logged to total depth. Schlumberger ran a Platform Express triple combo (resistivity/density/neutron/gamma ray) log at 3940 ft. Next an 8-1/2 in. hole was drilled to 3955 ft. The well was then cored continuously to 4907 ft. The well deviation was built to 20 degrees west at the 9-5/8 in. casing shoe and the angle was held to total depth. Surface location is 2668 ft northerly along the section line and 845 ft westerly at right angles to the section line from the southeast corner of Section 26-T31S/R23E (MDB&M). Surface Lambert Zone 5 coordinates are: X = 1,562,098 ft and Y= 622,570 ft (NAD 27). Bottomhole coordinates are: X = 1,561,404 ft and Y = 622,638 ft, 67.5 ft north and 694.5 ft west of the surface location.

Core Acquisition (Task A.2.A)

Coring Equipment

The downhole coring equipment used was a 30 ft Baker-Hughes-Inteq 8-1/2 in. X 4 in. ARC-425 core bit with a fiberglass inner barrel (Figure 9). Baker's Electronic Magnetic Surveyor™ tool was used for core orientation on nine cores.

Mud System

The upper part of the hole was drilled with a fresh water based cypan gel mud which had a density of 9.3 pounds per gallon (ppg) at the 9-5/8 in. casing point (3940 ft). The mud system was completely changed over before drilling out of the 9-5/8 in. casing shoe. It was fresh water based cypan gel, density 8.6 to 8.7 ppg, funnel viscosity 38 to 40 seconds/quart, plastic viscosity 11 to 15 centipoise, yield point 4 to 7, pH 8.3, chlorides 600 to 700 ppm, solids 2 to 5%. Mud resistivity at total depth was 1.72 ohmm @ 102°F, mud filtrate resistivity 2.23 ohmm @ 90°F, and mud cake resistivity 1.600 ohmm @ 90°F. The mud was supplied by Enterprise Drilling Fluids.

Surface Equipment and Procedure

A core "shuttle" was used to move the flexible fiberglass inner barrel from the derrick to the catwalk. The shuttle was a piece of 9-5/8 in. casing with a screw-on cap on the lower end. Once the core was cut and brought to the surface the inner barrel was pulled from the assembly while it was held in the rig's rotary table. The inner barrel was then placed in the shuttle, which was in the rig's mousehole. Next, the core shuttle was winched to the catwalk as shown in Figure 10. Wedges had been welded onto the catwalk to cradle the core shuttle and act as a target for the rig hand who was lowering the core. This kept any jostling of the core to a minimum, especially important because we did not want to induce any fractures in the core.

The core was then pulled from the core shuttle onto a special core table designed by Baker-Hughes-Inteq for recovering friable core, which is shown in Figure 11. The table was placed about three feet from the end of the catwalk, but level with the inside of the core shuttle. A winch cable was clamped to the inner barrel and it was pulled gently from the core shuttle until it was completely exposed.

Next the core was marked with depth annotations and divided into three foot lengths. Gas powered rock saws were used to cut the core into three foot lengths. The three foot sections were then transferred to the back of a pickup truck where they were capped, flushed with helium gas, sealed, and placed in a padded refrigerated box (35°F) for transport to Core Laboratories. Each core was transported to the lab immediately after it was cut. Care was taken to keep the core from freezing.

Recovery Information

A total of 32 cores were cut from 3955 to 4907 ft. Over this interval of interval of 952.8 ft, 948.1 ft of core was recovered. A detailed description of the coring is shown in Table 1.

Table 1. Core Recovery, Chevron 653Z-26B, Buena Vista Hills Field, Kern County, California

Core	Depth	Cut	Recovery	Comments
1	3955-3985	30	28.9	
2	3985-4015	30	30.7	
3	4015-4045	30	29.5	Oriented
4	4045-4075	30	28.5	Oriented
5	4075-4105	30	31.3	Oriented
6	4105-4135	30	30	
7	4135-4165	30	30	
8	4165-4196	31	31	
9	4196-4227	31	31	
10	4227-4258	31	31	
11	4258-4289	31	30.8	Oriented
12	4289-4320	31	31	Oriented
13	4320-4350	30.4	30.4	Oriented
14	4350-4381	31	31	
15	4381.4-4411.5	30	30.1	
16	4411.5-4441.7	30.2	30.2	
17	4441.7-4471.9	30.2	30.2	
18	4471.9-4502	30	30.1	
19	4502-4532	30	30	
20	4532-4561.8	30	29.8	Oriented
21	4561.8-4592.4	30	30.6	Oriented
22	4592.4-4622.7	30	30.3	Oriented
23	4622.7-4652	30	29.3	
24	4652-4681.8	30	29.8	
25	4682-4711.4	30	29.4	
26	4712-4741.8	30	29.8	
27	4741.8-4771.1	30	29.3	
28	4772-4785.7	16	13.7	Jammed
29	4786.6-4817	30	30.4	
30	4817-4847	30	30	

Table 1 Cont. Core Recovery, Chevron 653Z-26B, Buena Vista Hills Field, Kern County, California				
Core	Depth	Cut	Recovery	Comments
31	4847-4877	30	30	
32	4877-4907	30	30	

Field Wettability Measurements (Task A.3.A.)

Wettability measurements were made on core samples by the mudloggers. They followed an ingenious protocol developed by Deborah Lerner of Chevron Petroleum Technology Company and Gena Evola of Chevron U.S.A. Production Company. Wettability is difficult to measure because it is affected by so many environmental factors and may be changed by the coring process.

Technique

Dispersion Test. Pieces of the sample that are free of drilling mud are hand selected and crushed in a metal mortar with a metal pestle until it passes through a 500 micron sieve. The ground sample, which now resembles loose fine-grained sediment, is split in half. One half of the sample is placed in a glass jar with about 30 cc of filtered produced brine, and the other half is placed in a glass jar with about 30 cc of depolarized kerosene. Each jar is agitated and the dispersion of the sediment is observed. It is also noted if the kerosene becomes discolored by the sample. A completely water wet sample will totally disperse in the brine. In the kerosene it will form a clump at the bottom of the jar, minimizing the surface exposure to the brine. Oil wet samples will behave the opposite, dispersing in the oil, clumping in the brine.

Drop Tests. Samples for the drop tests should be carefully selected; fresh bedding plane surfaces are used for each drop test with a preference for using opposing samples from the same surface for the brine drop test and the oil drop test whenever possible. Do not use surfaces that have come in contact with drilling mud.

For the brine drop test, the sample is placed in the bottom of a beaker full of depolarized kerosene. A drop of produced brine is carefully placed on the bedding plane surface and the angle of incidence of the drop to the sample and the shape of the drop is observed.

For the oil drop test, the sample is placed in a metal clamp and submerged in a beaker filled with produced brine. A drop of produced formation crude oil is carefully placed on the *underside* of the sample and the shape and angle of incidence of the drop to the sample is observed.

In these tests spreading of the drop is interpreted as wetting behavior. For a truly water wet sample, a drop of brine placed on top of the oil-submersed sample will spread out flat. Conversely, the drop of brine will remain completely spherical on top of an oil wet sample, minimizing the area of contact. The oil droplet will spread on an oil wet sample and remain spherical on a water wet one.

Oil Adhesion Test. The sample that was used for the oil drop test is considered to be saturated in brine. This same sample is removed from the brine and dunked in a beaker of produced formation crude oil. The oil coated sample is then carefully removed from the beaker and placed in the bottom of a beaker of produced brine. The reaction of the crude oil on the sample is observed. Major adhesion of the oil to the sample is associated with oil wet behavior since the rock tends to stay in contact with the oil instead of releasing it in preference to the brine.

Results

Wellsite wettability tests were performed by Bill Gilmour of Horizon Well Logging within 2 hours of the core reaching the surface. Chip samples removed from the bottom of each core segment were used for the tests. Typically 2 samples were analyzed per 30 ft core. Because samples were taken within 1 cm of saw cut surface to avoid fracturing the core, wettability may have been affected by heat from saw.

Wettability appears to be neither strongly water or oil wet for the most part, although some samples exhibited slight oil wet behavior and some water wet behavior. Sandstone laminae (basal thin sands in 2-3 in graded beds) typically appear water wet. The samples were consistently water wet below 4570 ft.

Anelastic Strain Recovery (Task A.3.B.)

Anelastic strain recovery measurements were made at the wellsite on oriented core shortly after it was brought to the surface. This technique measures the microscopic expansion of the core due to the release of overburden pressure, giving the orientation of principal strains. Knowing the principal strain orientation one can infer the *in situ* tectonic stress orientation that can be used for both natural fracture prediction and induced fracture stimulation planning.

Technique

TerraTek's ASR^{3D} System monitors core relaxation with twelve LVDTs (Linear Variable Differential Transducers), mounted against each sample in multiple directions. The displacements measured by these transducers are recorded on a portable personal computer, which controls the measurement program. A thermal chamber, equipped with a solid state heat pump is used to maintain the samples at constant temperature during testing. The sample is mounted in an Invar fixture (invar has a low coefficient of thermal expansion).

The relaxation strains on a core are measured in six different directions. Three orthogonal strain measurement are made parallel and perpendicular to the core axis. An additional three strain measurements are made at 45° to these measurement, in three distinct directions. This provides enough data to perform a transformation to uniquely determine the magnitudes and directions of the principal strains by solving for the roots of a cubic equation and by manipulating the direction cosines. These orientations are relative to the principal scribe. They are further transformed to a conventional vertical-horizontal coordinate system by using the core orientation survey.

Preliminary Results

Strain relaxation data were obtained on 10 samples: four in the Brown Shale, three in the upper Upper Antelope, and three in the lower Upper Antelope. The results of the strain relaxation measurements are summarized in Table 2, below. All of the samples actually shrank in at least one direction.

Table 2. Principal Strain Directions, Anelastic Strain Recovery

Sample	Core Depth (feet)	ε_1		ε_2		ε_3	
		Azimuth (magnitude)	Inclination	Azimuth (magnitude)	Inclination	Azimuth (magnitude)	Inclination
1	4019.25 - 4019.90	139.72 (-4)	66.41	241.15 (-38)	65.59	113.39 (-53)	35.13
2	4022.35 - 4023.00	59.37 (-42)	50.37	288.35 (-52)	51.66	174.48 (-82)	62.83
3	4084.85 - 4085.50	76.62 (-95)	58.49	314.5 (-186)	45.42	160.71 (-263)	48.36
4	4094.05 - 4094.70	312.27 (352)	65.46	129.28 (68)	24.57	221.8 (-932)	88.87
5	4273.00 - 4273.65	222.22 (219)	23.01	84.79 (73)	72.63	350.11 (-172)	75.38
6	4287.35 - 4288.00	12.21 (205)	15.99	216.5 (-63)	75.37	124.85 (-291)	83.69
7	4537.00 - 4537.60	213.69 (75)	47.79	116.31 (-3)	81.96	18.34 (-7)	43.46
8	4537.75 - 4538.35	305.41 (92)	41.18	202.10 (-21)	78.33	102.48 (-33)	512.22
9	4612.00 - 4612.60	219.59 (46)	24.67	345.21 (-127)	75.02	80.51 (-186)	70.87
10	4612.60 - 4613.20	222.31 (-71)	17.31	315.32 (-183)	89.05	45.61 (-223)	72.73

The samples were inhomogeneous (most contained "soft" layers). Because of the inhomogeneity there is not necessarily a one-to-one correspondence between principal strains and stresses. Making certain assumptions on the mechanical properties, parallel and perpendicular to bedding, transversely isotropic analysis was used to calculate principal stress directions. These mechanical properties were based on experience only and could impact which stress acts in which direction. This can be resolved by specific evaluations of the regional and local geology and directions may need to be further evaluated (i.e., it is possible that the maximum and minimum stress components may switch.

The calculated stress directions (based on assumed material properties) are shown in Table 3, below. Note that 180° azimuth variation is acceptable. A stereonet plot of the maximum principal stress axes is shown in Figure 12.

Table 3. Principal Stress Directions, Anelastic Strain Recovery							
Sample	Core Depth (feet)	σ_1		σ_2		σ_3	
		Azimuth	Inclination	Azimuth	Inclination	Azimuth	Inclination
1	4019.25 - 4019.90	241.15	65.59	11.39	35.13	139.72	66.41
2	4022.35 - 4023.00	59.37	50.37	174.48	62.83	288.35	51.66
3	4084.85 - 4085.50	76.62	58.49	160.71	48.36	314.5	45.42
4	4094.05 - 4094.70	221.8	88.87	129.28	24.57	312.27	65.46
5	4273.00 - 4273.65	84.79	72.63	222.22	23.01	350.11	75.38
6	4287.35 - 4288.00	216.5	75.37	12.21	15.99	124.85	83.69
7	4537.00 - 4537.60	18.34	43.46	213.69	47.79	116.31	81.96
8	4537.75 - 4538.35	202.10	78.33	102.48	512.22	305.41	41.18
9	4612.00 - 4612.60	80.51	70.87	219.59	24.67	345.21	75.02
10	4612.60 - 4613.20	45.61	72.73	222.31	17.31	315.32	89.05

Laboratory Analyses

Laboratory Wettability Testing (Task A.3.B.)

The table below summarizes the status of the cleaning process. The total throughput shown in Table 4 is from January 10, 1997 to date. About half of the samples are nearing the end of the cleaning process (indicated by "very light yellow" coloration).

Table 4. Summary of miscible flow-through cleaning, wettability samples			
Sample ID	Sample Depth (feet)	Total Throughput of Solvent (cc)	Color of Effluent
1	3989.20	980	very light yellow
2	4040.90	385	yellow
3	4269.80	5740	very light yellow
4	4288.20	875	light yellow
5	4315.60	3840	very light yellow
6	4355.95	1960	light yellow
7	4414.30	**	**
8	4500.95	4055	very light yellow

Table 4 Cont. Summary of miscible flow-through cleaning, wettability samples			
Sample ID	Sample Depth (feet)	Total Throughput of Solvent (cc)	Color of Effluent
9	4601.0	2220	very light yellow
10	4679.30	670	light yellow

** - Sample deemed too tight for testing.

Wettability measurements have been delayed by the amount of time it is taking to miscibly clean the selected samples in preparation for actual wettability measurements. All samples are still cleaning at this time and one sample has been eliminated from measurement consideration due to the inability to flow fluids through the sample in a reasonable time frame. Miscible cleaning is required to prepare the sample for testing without altering the pore geometry of the sample. As such, further testing is not possible until such time as the samples are completely cleaned and prepped for testing. We are expecting to have the samples cleaned and ready for testing in approximately one month.

Spectral Core Gamma Scan (Task A.3.C.)

The spectral core gamma scan was performed on all core material to determine potassium, uranium and thorium concentrations in the core material. In addition, bulk density index, total gamma values and uranium-free gamma values were measured. The data was reported in graphical form as well as electronically via floppy disk. This task is complete.

Slab Core (Task A.3.D.)

The conventional core material was slabbed parallel to the axis of the core exposing maximum dip angle whenever possible. The slab was a 1/3 - 2/3 cut with the 1/3 section being used for photography and Imagelog™ analysis (Subtask O) and the 2/3 section being used to drill sample plugs for Dean Stark PK&S analysis (Subtask F) and other advanced rock properties measurements. The 1/3 slab material was cleaned and mounted in Styrofoam inserts for incorporation into slab boxes for viewing and description (Subtask E). The 2/3 section was returned to the conventional core boxes.

Detailed Core Description (Task A.3.E.)

Preliminary observations have shown that the Brown Shale interval contains almost no sand beds and appears to be quite siliceous. The first sand bed is encountered just above P point and sand beds are quite common throughout the rest of the core. Permeable appearing sand beds are commonly about 1 to 2 cm thick. A total sand thickness of about 35 ft was counted in the Antelope Shale, so the reservoir averages about 4% sand beds.

Porosity, Permeability, and Fluid Saturations (Task A.3.F.)

One-inch diameter plugs were drilled every foot from the 2/3 slab section of the conventional core parallel to bedding strike for porosity, permeability and saturation analysis (PK&S). The samples' fluids were extracted using a Dean Stark process (toluene) for removal and measurement of water volumes and a soxhlet extraction technique (methylene chloride and methanol) for removal of residual salt and oil components. The samples were then humidity dried until the weight stabilized. Porosity and permeability values (Klinkenberg and air values) were measured at three confining stress values (2100 psi, 2700 psi and 3500 psi) using Core Laboratories' CMS-300™ equipment. A summary of the average data is presented in Table 5.

Table 5. Summary of Averages, 2700 psi overburden pressure							
	Porosity (%)	Kl (md)	Kair (md)	Oilsat (%PV)	Watsat (%PV)	GD (g/cc)	n
Brown Shale 3939-4242	27.1	0.031	0.054	15.1	81.7	2.31	277
Upper U. Antelope 4242-4552	27.9	0.067	0.116	14.7	78.7	2.36	305
Lower U. Antelope 4552-4907	30.3	0.052	0.098	11.6	84.9	2.39	352
Total	28.6	0.049	0.087	13.6	82.0	2.36	935

With the completion of the conventional core porosity and permeability measurements, initial work is ready to begin on the hydraulic units identification and correlation to petrophysical properties yet to be measured. Future work in this area will be complemented by specific liquid permeabilities, capillary pressure measurements and relative permeability measurements which will get underway in 1997.

Of the preliminary analysis of PKS data, the most interesting aspects relate to matrix density variation and mini-permeameter data. Figure 13 shows that matrix density data is approximately linear with depth reflecting a change in character of Opal-CT with depth. This change affects the estimation of porosity from density and possibly neutron logs. The change can be due to a

- contraction of lattice dimensions
- decrease in externally bound water
- increase in authigenic quartz
- a combination of the above

Another interesting aspect of the PKS data is an apparent discrepancy between plug air permeability and profile permeameter results. Our experience with similar rocks in an adjacent field suggests that there is a one-to-one relationship, although noisy, between plug and profile permeameter results. Figure 14 shows the a comparison of plug and profile perm results. The overall ratio is closer to 10:1 (profile perm to PKS). Many plug samples are between 1:10 and 1:100 compared with profile perm measurements at the same depth. The PKS results fail to support local increases in permeability indicated by profile permeameter.

Profile Permeametry (Task A.3.N.)

The 1/3 slab section of the conventional core material was analyzed at a rate of 20 measurements per foot using Core Laboratories' Pressure Decay Profile Permeameter (PDPK™). The Klinkenberg and air permeability values were reported electronically via floppy disk. The measurements will be integrated with the permeability measurements made at stress on core plugs in an effort to develop a transform between the two data sets. Such a relationship will allow for better interpretation of the heterogeneity of the cored interval. In addition, relationships between permeability and lithology variation may be developed.

Core Photography and Core Imaging (Task A.3.O.)

Composite photography in white light and ultraviolet light was completed during 1996 using a format of 18 ft per print. The photos were scanned using PhotoCD format. The ultraviolet images will be used to quantify lithology and pay intervals on a small scale for integration in a core-log transform. Using Core Laboratories' Imagelog™ software, the ultraviolet images have been converted into binary images with the pay intervals being integrated to determine net pay in the cored interval. Binary images were generated using Core Laboratories' proprietary software allowing pay zones to be identified and summed over the entire cored interval. Future work could entail varying the threshold fluorescence for pay zone determination, giving a range of possibilities, and identifying net zones based on lithology.

Wireline Log Analysis (Task A.2.B and A.5)

Introduction

As part of the evaluation of the Chevron/DOE Buena Vista Hills Field , 653Z-26B well, Schlumberger was commission to run the following services:

Array Induction Tool	AIT
Spontaneous Potential (multiple passes)	SP
3 detector Litho-density sonde	LDS
Compensated Neutron Log	CNL
Array Porosity Sonde	APS
Natural Gamma Spectroscopy	NGS
Micro Cylindrical Focus Log	MCFL
Electro Magnetic Propagation Tool	EPT-G
Micro Log	ML
Combinable Magnetic Resonance	CMR
Formation Micro Imager	FMI
Dipole Shear Sonic	DSI
Cross Dipole Anisotropy Log	DSI
Environmental Capture Sonde	ECS
Modular Dynamic Tester	MDT
Reservoir Saturation Tool	RST
Ultra Sonic Imager	USI
Cement Bond Tool	CBT

To date most of the data acquisition has been completed with the remaining carbon/oxygen (RST) + production logging to follow in the near future. Consolidation of the data has taken place with distribution of the raw data and field/final prints through to Chevron. Analysis to date has been consolidated with available core data results. Further analysis of some of these data are waiting on results of T2 analysis, mechanical properties from TerraTek, X Ray and

CT scanning as well as further oil analysis results from Chevron. The results have been presented in Montage form for better correlation among the data.

Scope of Remaining Work

Perform a complex lithology evaluation of the well, using the acquired suite of logs. Incorporate the third party data such as core analysis, full core observations as well as any other information that might be relevant to the petrophysical analysis.

Targeted Results

Oil Saturation in place has been a targeted result. Several approaches to acquiring saturation include Dual Water saturation analysis, ELemental volumetric ANalysis (ELAN) including the ECS/NGS log data using mineral-based error minimization log analysis, saturation from magnetic resonance log (CMR) processing, as well as saturation from carbon/oxygen log (RST) processing will be thoroughly analyzed and compared to whole core data results.

Permeability analysis is another targeted result from this analysis. The permeability is being approached from several methods including permeability from conventional open hole logs, relative permeability from MDT tests, as well as the use of the CMR.

Porosity is being analyzed by comparing and contrasting the evaluated porosity from five open hole logs (LDS, CNL, APS, DSI, CMR) to core porosity.

Rock Mechanics is being analyzed through the use of conventional open hole logs as well as the MDT and DSI. The resultant information will be compared to the laboratory measurements from TerraTek.

Formation Anisotropy is calculated from the Cross Dipole measurements of the DSI tool. This analysis will give a relative percentage of anisotropy variation versus depth in the well bore.

Oil Viscosity is sought as a targeted result. Continuos viscosity measurements are attempted through the use of the CMR log processing.

Structural / Stratigraphic / Fracture Analysis will all be acquired through analysis of the FMI data. These data are analyzed to add geologic knowledge about the structure, deposition, relative fracture size, frequency, strike, magnitude, and direction of the fractures. Comparing these data with the DSI anisotropy can add to the understanding of tectonic stresses present in the area.

Preliminary Results

The logs are presented in a montage format (Figure 15). This format allows for a quick and encompassing look at the evaluation of the information gathered. These data are at different stages of task completion in that raw data is presented in addition to Schlumberger interpreted analysis and off site analyzed core data. Using this format, all of the data can be compared and cross analyzed for anomalies and trends which can be further studied.

Findings to Date

The siliceous shale of Buena Vista Hills field challenges standard traditional wireline log interpretations. The formation matrix density is lower than that normally encountered in sands (see Figure 13), which skews the porosity derived from logs when the matrix density is set to 2.65 g/cc, a standard for sandstone environments.

The higher formation porosity also causes challenges for compensated neutron log porosity algorithms. The neutron porosity reads lower than true porosity. The fact that the siliceous shale is a siliciclastic rock makes it tough for traditional analysis since "quartz type sandstone" will not traditionally have this high porosity with low permeability simultaneously.

Because of the complex lithology, i.e., the higher porosity siliceous shale has much lower permeability than the sands, standard open hole log empirically-based porosity/permeability transforms hold little basis in reality on these rocks.

The low permeability of the rock leads to an initial conclusion that unless open fractures are present, the primary transfer of fluids from the formation to the wellbore is due to water imbibition. The overall resistivity of the rocks is what might be considered "nondescript" when a traditional water saturation equations are used.

Formation acoustic transit times are slow compared to many common siliciclastic rocks. Buena Vista Hills Antelope Shale appears to have less acoustic attenuation than many other areas of siliceous shale seen in the region: the compressional wave slowness data was successfully acquired and measurable. Shear wave slowness in this rock is moderate, ranging from 180 - 280 microseconds per ft. Many areas in this region might show comparable slowness in excess of 350 micro seconds per foot.

Magnetic resonance of the formation appears to be a valuable tool for indication of rock parameters such as porosity, bound fluid, hydrocarbon typing, permeability, and residual oil saturation. These measurements used in conjunction with the other open hole data give a good analysis through zones of varying lithology and lamination thickness. Looking at the CMR log and tying in the station logs from the CMR, we can see what appears to be a relatively laminated oil column of viscosity ranging from 2 - 10 cp throughout the Antelope Shale.

The montage contains preliminary analysis incorporating all of these data, as well as formation evaluation from Dual Water analysis, ELAN analysis, superimposed upon core analysis data provided by Core Laboratories. The correlation of core porosity to CMR porosity tends to be quite good over the majority of the well. This correlation is inexplicably varied above 4050 ft and will require further analysis. Permeability is based on published permeability transform from magnetic resonance, and normalized to the core data. Residual oil saturation calculated from CMR T2 distributions using standard cutoffs on the for other areas of siliceous shale. Is similar to core oil saturations.

Wireline Log Montage

Dipole shear anisotropy as well as MDT data and the ELAN analysis were used to compute the mechanical properties of the formation versus depth. Young's modulus and Poisson's ratio as well as the pore pressures derived from the MDT were input into Fracade to derive the analysis of the horizontal stress and static rock properties used in completion design. This information will be important during the planning and simulation of hydraulic fracturing. Analysis of the main to repeat pass of the anisotropy log shows a very good repeatability within +/- 5 degrees as seen by the polar plots on the montage.

The Elemental Capture Sonde was run and its initial analysis showed a large percentage of quartz, feldspar, and mica, with a fairly uniform clay and carbonate stringers. Further analysis has not been completed yet as we wait for a special core analysis data.

The Formation Micro Imager (FMI) was used to define parameters of structural deposition, textural studies versus core, core orientation, and fracture analysis. Analysis of a curve representing the orthogonal direction to borehole ovality as seen on the FMI calipers versus. the Dipole Shear Imager (DSI) anisotropy shows an interesting anomaly. At 4250 ft we see a rotation of the caliper breakout direction which rotates around to match the DSI anisotropy direction below that point. This is also approximately the same depth that we noted a change in pressure from the MDT. Dipole anisotropy values varied throughout the well bore with a magnitude change happening here also. Comparing the variable energy from the DSI to the FMI fracture analysis showed no initial comparison in fracture frequency to differential sonic energy. Further analysis is required to isolate other log responses that correlate to the variable energies.

Further Work

- Dipole Shear Anisotropy as compared to further work on core stress analysis by Terra Tek and stress from the shear wave VSP.
- Lab NMR measurements of core samples and oil samples to further refine the CMR interpretation.
- Logging of RST to compare Cased Hole Saturation in a static environment to the possible invaded open hole environment.
- ECS elemental interpretations versus core chemical analysis.
- Production Logging to verify flow rates and fluid volume and types from intervals.
- Other interpretations as anomalies are uncovered.
- Complete the FMI to Core depth correlation.

Fracture Characterization

Shear-Wave Birefringence VSP (Task A.4.A)

The Buena Vista Hills multicomponent vertical seismic profile (VSP) survey was recorded in Well 653Z-26B on Nov. 14-16, 1996, primarily for the purpose of evaluating stress and fracture effects as a function of depth. Stress and fracture evaluation is possible from an analysis of shear waves as they propagate through the various formations. The data also have potential use for imaging both P-wave and S-wave reflections from interfaces near the wellbore. The essential VSP hardware consisted of a multicomponent seismic source at the surface and a clampable three-component geophone on a wireline that traversed the entire well and furnished data to a recording system at the surface. A monitor geophone had been planted earlier at a depth of 300 ft near the source location to provide an accurate zero time. VSP recording began the morning of the 11/14, but a severe noise problem identified as tube-wave contamination soon became apparent. Recording was stopped at that point so that more liquid could be bailed out of the well to eliminate the tube wave. Recording resumed by the afternoon of the 15th with no sign of tube wave contamination. By the morning of 11/16, 48 VSP levels had been recorded at intervals of 100 ft from 4830 ft to 130 ft. Data on field records appeared to be of outstanding quality. Initial processing revealed unexpected source-generated noise in the S-wave data at some levels, but this subtracted out during subsequent processing steps. The birefringence analysis was expected to be completed during the 1st quarter of 1997 with P-wave and S-wave reflection imaging to follow shortly thereafter.

Cross-well Seismic Acquisition and Processing (Task A.4.B)

During the 4th quarter of 1996, John Fairborn completed a modeling and planning study for the upcoming crosswell work. The purpose of this effort was to reassess the original DOE proposal now that we have well-log and core data from the 653Z well. His reassessment was run under the assumption that we would use Paulsson Geophysical Inc.'s downhole vibrator as the energy source.

The results of the modeling showed that:

1. Velocity anomalies related to structure or fractures have to reach dimensions of 100 ft or more to be detected by crosswell tomography.
2. If the injected CO_2 remains in gas phase, lowers the velocity by a reasonable amount, and has horizontal dimensions of 100 ft or more, then it can be detected by crosswell tomography. The limiting vertical dimension for tomography detection will be several tens of feet. It can be much less than that, 5 feet or so, for reflection imaging.
3. Reflection amplitudes within the undisturbed formation are liable to be small because of the small reflection coefficients. The presence of gaseous CO_2, however, could create a significant velocity drop and give rise to a relatively strong reflection.
4. It seems reasonable to expect that CO_2 in a gas phase will create the velocity drop that we speculate upon here, particularly since the formation porosity is high. Assigning it a value of 10 percent is a judgment based on observations from CO_2 injection in other reservoirs with similar porosity.

5. The velocity drop and the detection scale are roughly related in an inverse-linear manner. That is, a 5 percent velocity drop, one-half that used in these examples, would double the detection threshold to about 200 feet.
6. Zones of high fracture density may also be associated with increased attenuation and/or velocity anisotropy. Modeling anisotropy or attenuation is more difficult than modeling velocity. Codes for doing this are still in the research phase.

Based on the results from this study, Chevron Petroleum Technology Company and Chevron U.S.A. Production Company agreed to continue with plans to obtain cross-well seismic data during the first quarter of 1997 for the purposes of reservoir characterization (using both reflection data and P-wave first arrivals for attenuation analysis) and time-lapse monitoring (using tomography). While Bjorn Paulsson Geophysical Inc. continued their efforts to complete the development of their downhole vibrator, discussions were initiated with Tomoseis in early February 1997 to arrange a field trial of their piezoelectric source tool in the B.V. Hills pilot area. A previous test conducted in the pilot area by Tomoseis showed that placing hydrophone receivers in existing slotted-liner wells was too noisy (due to the presence of gas-bubble generated noise) to record useable crosswell seismic data. However, since that first attempt, well 653Z had been drilled in the center of the pilot, and as of February 1997 it remained unperforated. Thus, 653Z represented a well with optimally quiet conditions for placing the receivers. The field trial with Tomoseis was scheduled to commence during late February 1997.

Borehole Imaging Analysis (Task A.4.C)

Schlumberger completed an analysis of the FMI data from well 653Z during the fall of 1996. Figure 16b shows a typical FMI image from the lower Upper Antelope with bedding resolved down to 0.1 ft. Also shown in the figure are examples of a fault and a fracture and the matching core. Figure 17 shows an upper hemisphere equal area net of all the planar features that were identified on the FMI over the interval 3952 ft to 4902 ft. The poles to bedding planes in Figure 17 (green squares) show a tight clustering of dips that average 10.9° with an average dip azimuth of N34°E. The red, dark blue and light blue squares show fractures of different qualities ("A" being of highest quality and "C" being of lowest quality). Figure 18 shows an azimuth histogram for these fractures. While there are numerous azimuths represented in Figure 18, the most abundant are in the S40°E to S45°E direction. Figure 19 shows a dip histogram for the same set of fractures and shows that dips range from 10° to 90°, but that the most common occurrence is between 80° and 90°.

The orange squares, pink squares, and pink X's in Figure 17 show faults, microfaults, and healed fractures respectively. Figure 20 shows an azimuth histogram for these features. Like those of the fractures already discussed, there are numerous azimuths represented in Figure 20 but the most abundant are in the S40°E to S45°E direction. Figure 21 shows a dip histogram for the faults, microfaults, and healed fractures and shows that dips range from 10° to 80° with only a slight preference for the 50° to 70° degree dip range.

High Resolution Structural Mapping (Task A.4.D)

During the 4th quarter 1996, work was begun on building an OpenWorks™ (Landmark Graphics Corp.) database containing all Buena Vista Hills wells that penetrate the Brown and Antelope Shales. By mid-February 1997, approximately 200 wells had been loaded to the database with another 20 more to be loaded shortly thereafter. Data for the 200 wells included surface locations, directional surveys, and digital open-hole logs. Arrangements were made to have the logs for the remaining 20 wells digitized by the end of the 1st quarter in 1997. Work was also begun on correlating formation marker tops in the Brown Shale and Antelope sections using StratWorks™ (Landmark Graphics Corp.). A total of 7 Brown Shale and 15 Antelope marker tops were being correlated. By mid-February, most of the 200 wells had been correlated and a list of observed fault cuts had been tabulated. Completion of the correlations, fault interpretations, and structure maps is expected in early 1997 upon completion of the log digitizing and subsequent addition of the remaining wells to the database.

Outcrop Study (Task A.4.G.)

The outcrop study has been completed as scheduled. The study includes: field work in Chico Martinez Creek and along the coastal central California, reinterpretation of borehole images and well logs from several wells in Buena Vista Hills and other Antelope Shale fields nearby.

We are extremely pleased about our production for the first year (see References for a list of presentations and publications). The most significant results of our work are the following: brecciated faults and connected open fractures are major hydrocarbon pathways in the Monterey Formation. These structures control hydrocarbon migration as well as a large volume of production. These results have been very effectively disseminated in the scientific community as well as in the energy industry. Several presentations have been made in national and international meetings attended mostly by the academics. Two affiliates programs at Stanford, the Rock Fracture Project and the Borehole and Rock Physics Project have provided excellent vehicles to reach the practitioners in the energy industry.

The project supported one graduate student, Sneha K. Dholakia who completed her Master thesis and is now working for Amoco Production Company at Houston, Texas. Presently, Judson Jacobs who is a first year graduate student is working on the project.

Except the delay in getting the initial funding, we have not encountered any serious problems.

After having convinced about the importance of breccia zones in hydrocarbon migration and flow, we refocused on the development and distribution of these structures.

This year we will be working on the new core and perhaps some old core and wellbore data. Based upon our past experiences, we recommend that a greater effort to be made towards the detection of breccia zones in producing reservoirs, a better documentation of their volumetric distribution, and a quantitative measure of their contribution to the actual hydrocarbon production.

Regional Tectonic Synthesis (Task A.4.H)

As part of the "Fracture Characterization" task within the Chevron/DOE Class III investigation, Advanced Resources International is conducting a Regional Tectonic Synthesis of the southern San Joaquin Basin, including the Buena Vista Hills oil field. The study area extends from near the Wheeler field (south of Buena Vista Hills) northward to the Lost Hills field, and covers much of western Kern County. The Regional Tectonic Synthesis is a two-part effort. Part I is the "Synopsis of Previous Investigations", which is in the final stage of completion. Part II is the "Structural Analysis and Natural Fracture Detection" and work is at the beginning stages.

Part I provides the geologic foundation for our analysis in Part II. In Part I we completed the geological literature search, obtained review copies of the most important literature identified by our search, complied a list of the essential maps and illustrations to be incorporated into the synthesis. This draft document includes a discussion of: 1) the scope of our literature review, 2) a broad geologic overview of the San Joaquin Basin, 3) tectonics and structural deformation of the southern and western San Joaquin Basin and 4) structural and reservoir characteristics of the Buena Vista Hills oil field.

Literature Review

The scope of our literature review is not intended to be comprehensive with respect to the geology of the San Joaquin Basin. Rather, the review focuses on the literature that provides specific information on: 1) a geologic and tectonic overview of the southern San Joaquin Basin, including relevant associated investigations of the Monterey Formation, 2) types and history of structural deformation within the southern and western San Joaquin Basin and 3) structural and reservoir characteristics of the Buena Vista Hills field. During our efforts to complete the literature review and critique, we realized that there appears to be relatively little published information on the Buena Vista Hills field. Unpublished information on the Buena Vista Hills field structure, reservoir and production was available for use from Chevron.

Studies published between 1900-1950 were largely involved with stratigraphy and biostratigraphy, as well as general outcrop observations and field mapping. During this time, the U.S. Geological Survey (USGS) published maps and several classic monographs still in use, including the treatises on the Monterey Formation and on the geology and oil resources of the southern San Joaquin Basin. After the 1950s, the geological emphasis on the San Joaquin Basin shifted to subsurface studies by petroleum companies and much of this work remains unpublished.

Between 1960 and 1990, the published literature consists mainly of university dissertations and geological society guidebooks including the American Association of Petroleum Geologists (AAPG), the Society of Economic Paleontologists and Mineralogists (SEPM) and the San Joaquin Geological Society. The USGS published other important investigations between 1970 and the early 1990s, including the comprehensive work on the Elk Hills field and the Cenozoic evolution of the San Joaquin Valley. Entire sections devoted to the geology of the San Joaquin Basin appeared in the Geological Society of America (GSA)

Decade of North American Geology monographs published between 1988 and 1992. Other major sources of published information on the San Joaquin Basin are the GSA Bulletin and the AAPG Bulletin.

Preliminary Findings

The literature review of the tectonics and modern stress state adjacent to the San Andreas fault, demonstrates a quick transition of structural concepts from pure shear models to a special case of transpression. It is now purported that the "weak" (i.e. zone of low friction) San Andreas fault system accommodates all of the strike-slip displacement and that the folds near the system are a result of the regional state of compression. For example, folded anticlines such as those of the major oil fields in the San Joaquin Basin were initially believed to be related to early simple shear displacements along the San Andreas fault. About 20 years ago, it was inferred that the periods of fold growth described in the subsurface along the west side of the San Joaquin Basin correspond to known and postulated episodes of strike-slip displacement along the San Andreas fault. Within the past ten years, however, stress state studies show that the direction of maximum horizontal compression is perpendicular to the San Andreas fault. With some fold axes oriented almost parallel to the San Andreas fault, it is now considered that fault-fold relationships consistent with thrust-fold belts are more appropriate in understanding the folds along the San Andreas fault system.

Another finding we made based upon our review and critique has to do with fault-fracture relationships within the Monterey Formation. Despite all the information gathered on Monterey rocks in the San Joaquin Basin and elsewhere in central California, there is still not a clear or consistent understanding of the fracture character and the relationship of fractures to faulting. Relatively few areas of surface-exposed faulting and associated fractures are available for detailed examination within the San Joaquin Basin. Some investigators have observed that highly fractured areas and intervals are not genetically related to folding or faulting, citing that some wells drilled into anticlines or close to faults frequently fail to find adequate fracture permeability and porosity in the Monterey Shale. Also, suitable fracture porosity and permeability are often erratically distributed on productive anticlines of Monterey and not present in the hinge line of folds or in the vicinity of faults. Many fractures in Monterey rocks, however, display systematic fracture orientations implying that the fractures did not develop in a hydrostatic stress field, and are more likely associated with faulting than with diagenesis. For example, it has been postulated that early-formed parallel fractures may have developed at shallow depth due to dewatering, coupled with faulting and gravity-induced down slope extension. However, recent work on fault/fracture relationships has shown evidence for fault-related fractures, and that these types of fractures are possibly caused by bedding slip during folding.

It can be argued that faulting controls hydrocarbon migration and production in the Buena Vista Hills and surrounding fields especially where the faults evolve from a preexisting discontinuity, forming a highly fractured or brecciated zone, along which migration occurs. These types of bed-parallel (and bed-perpendicular) faults have been observed and well documented throughout the Monterey Formation. The key to their existence is undoubtedly due to the tectonic deformation that occurred in this region during latest Miocene to Pliocene to Pleistocene to Recent, when the southwestern San Joaquin Basin experienced uplift, and crustal shortening due to thrust faulting and anticlinal folding. The overall configuration of folds and faults in the Monterey indicates extensive crustal shortening (compression) of between 12 and 17 percent in a N30-40E direction.

The importance of diagenesis cannot be overlooked in this case, because diagenetic overprinting of fractured rocks may heal fractures, as observed in chert and porcelanite horizons (Snyder, 1987), suggesting that the timing of deformation and diagenesis has a great deal to do with the production control. Another scenario thought to occur in Monterey rocks is localized tectonic fracturing superposed upon preexisting diagenetic structures, creating a maximum of interconnected fracture permeability, and an increased level of tectonic control of production.

Undoubtedly the control of Monterey Formation production is affected by all of these processes. It would appear that the occurrence and post-digenetic timing of tectonic deformation would have the most influence on economic production, and would be the most favorable model in terms of future exploration in the Buena Vista Hills and elsewhere in the San Joaquin Basin.

Reservoir Modeling and Simulation

None of the tasks under this process have been completed.

CO2 Pilot Flood and Evaluation

None of the tasks under this process have been completed, except for profile permeametry, already described under Reservoir Matrix and Fluid Characterization.

Figures

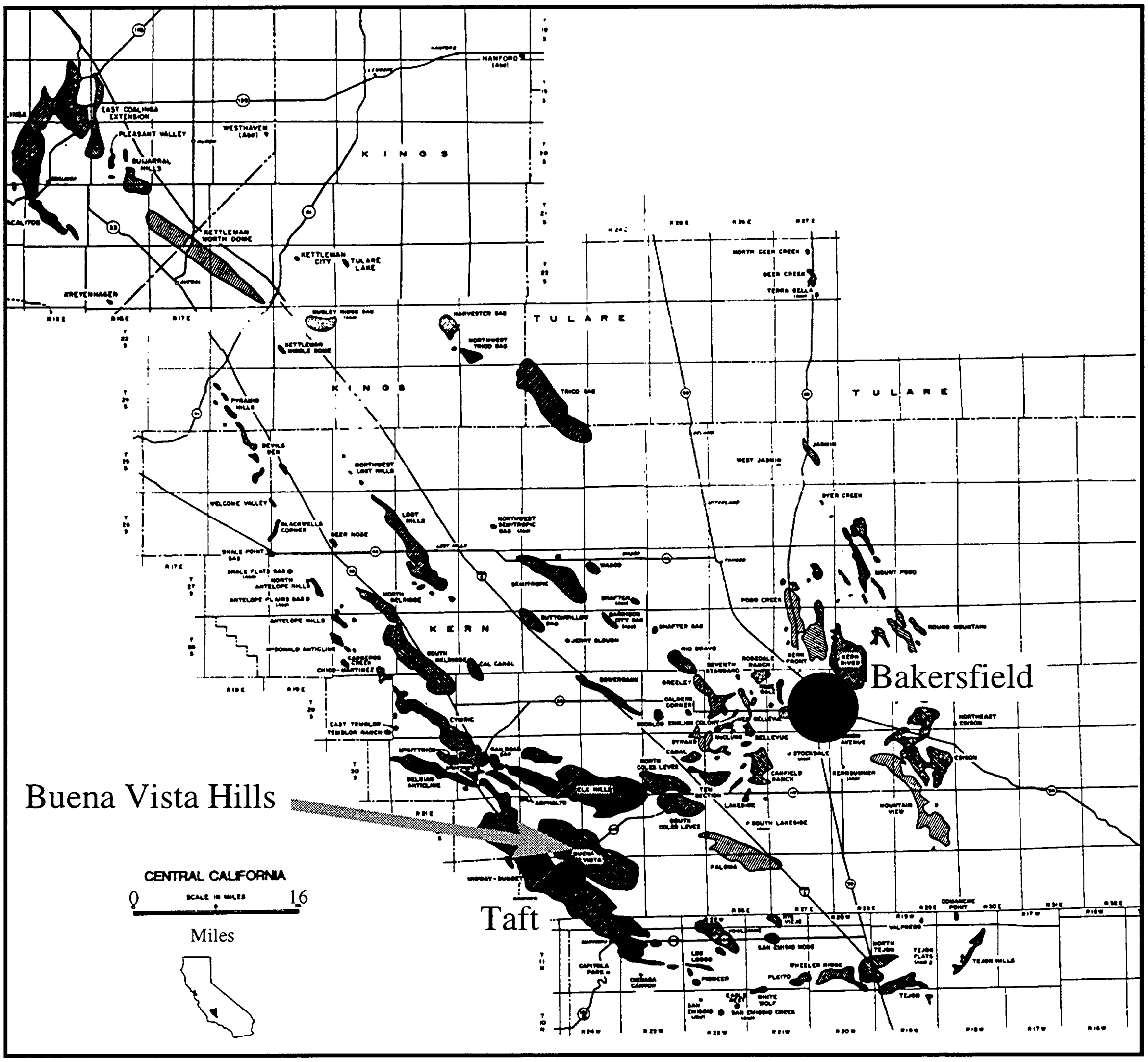
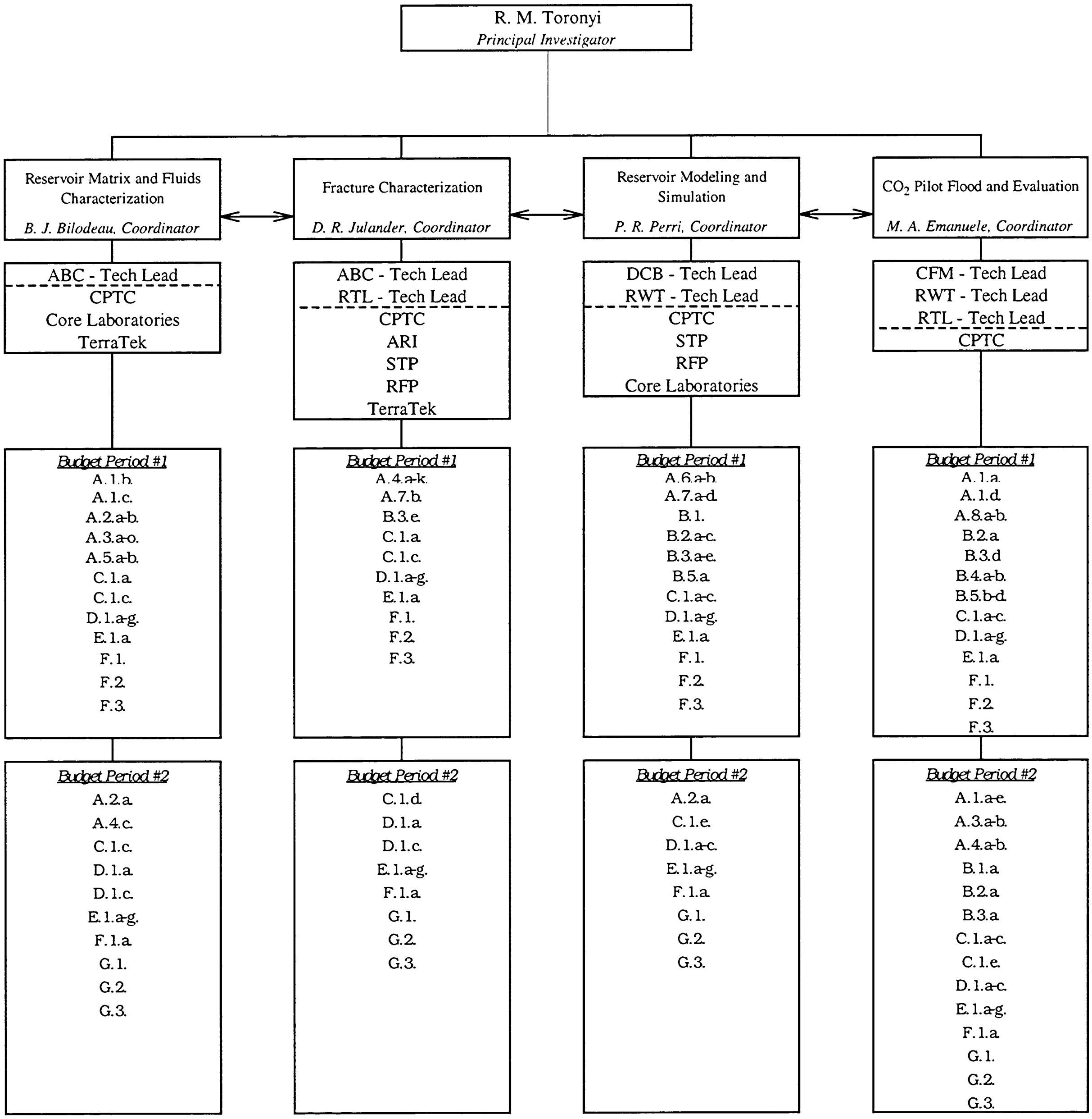


Figure 1. Regional map of southern San Joaquin Valley, Kern County, California

Chevron/DOE Buena Vista Hills Class III Reservoir Project



<u>CPTC Technical Leads</u>

DCB - D. C. Beeson - Geologic Modeling/Data Integration
ABC - A.B. Carpenter - Siliceous Shale Geochemistry and Petrology
RWT - R. W. Tang - Reservoir Simulation
CFM - C.F. Magnani - Reservoir Monitoring
RTL - R. T. Langan - Borehole Geophysics

<u>Technical Team Partners</u>

CPTC - Chevron Petroleum Technology Co.
ARI - Advanced Resources International, Inc.
STP - Stanford Seismic Tomography Project
RFP - Stanford Rock Fracture Project
Core Laboratories
TerraTek, Inc.

Figure 2. Project task process breakdown.

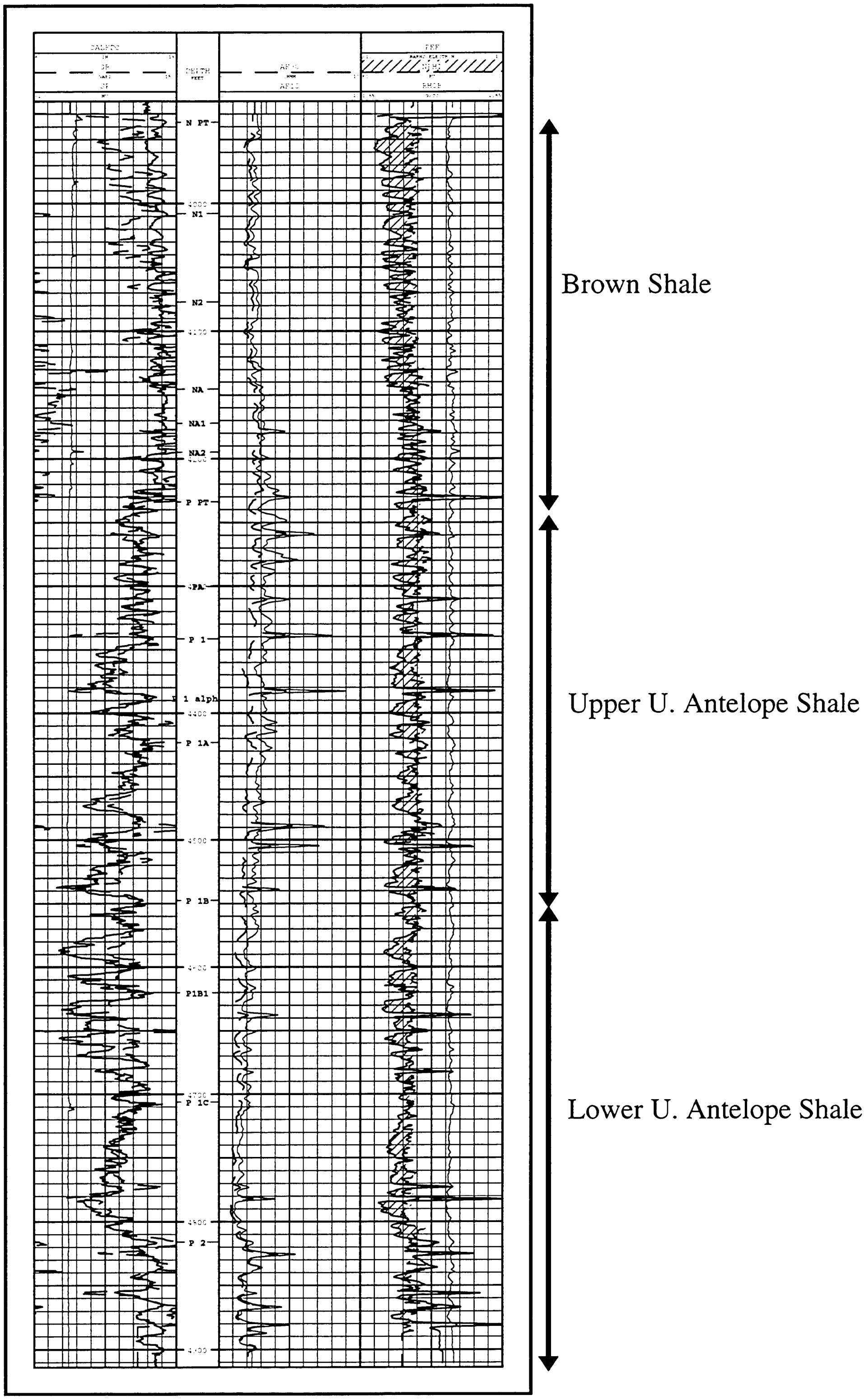


Figure 3. Resistivity/density log of Chevron 653Z-26B, Section 26-T31S/R23E.

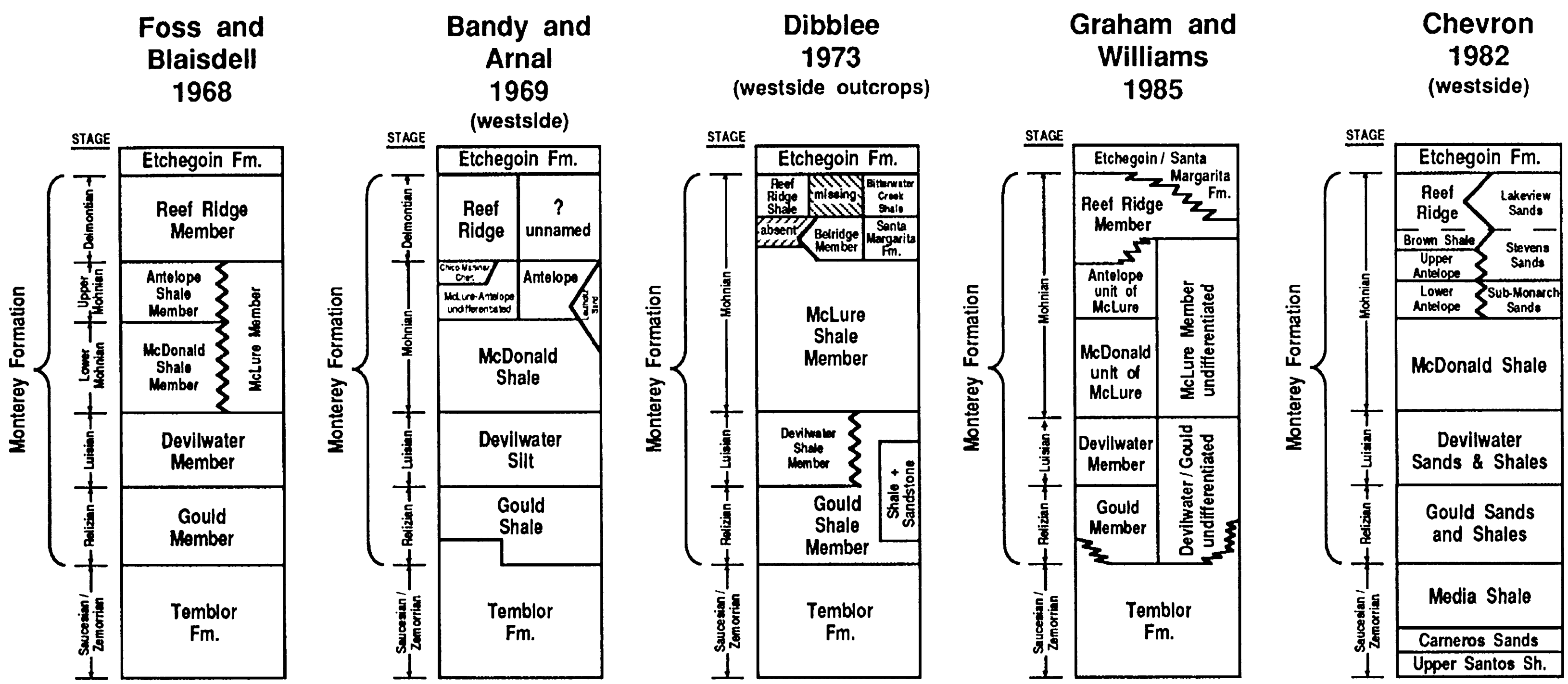


Figure 4. Stratigraphic columns of Monterey Formation Antelope Shale, southern San Joaquin Valley, California

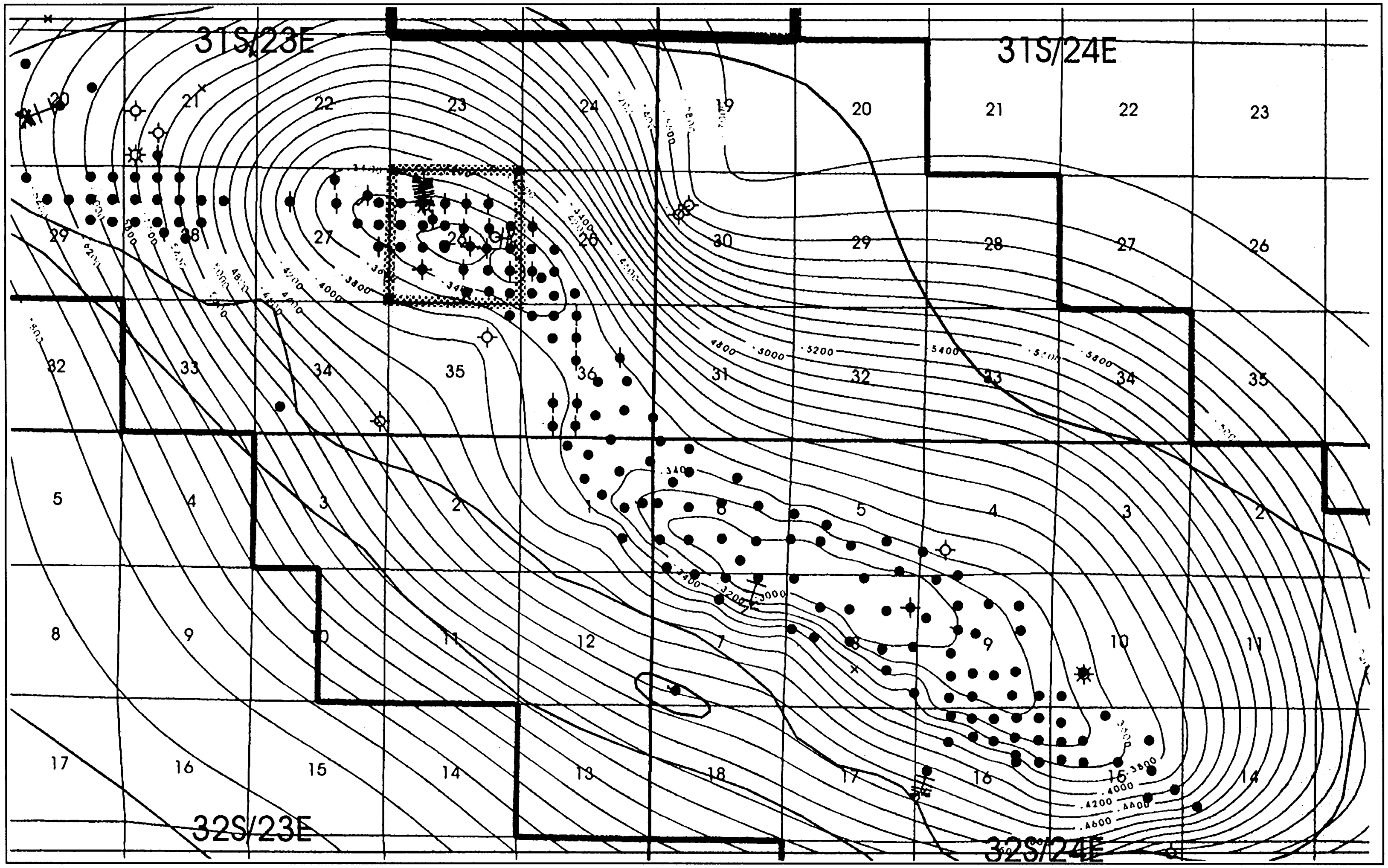


Figure 5. Structure contour map on the top of the Antelope Shale (P point), Buena Vista Hills field, Kern County, California. Section 26B is outlined by a stippled line.

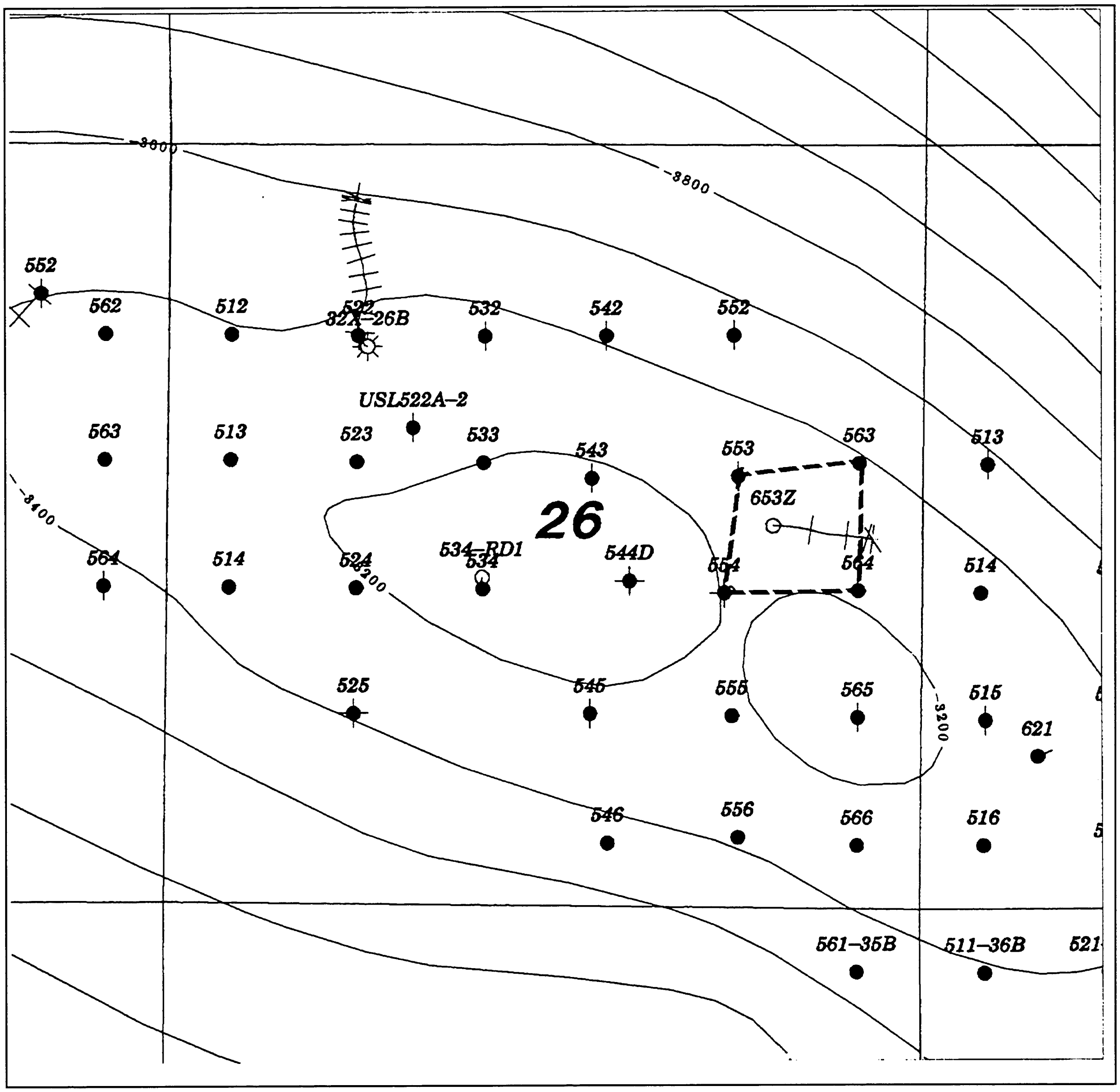


Figure 6. Structure contour map on the top of the Antelope Shale (P point), Section 26B-T31S/R23E, Buena Vista Hills field, Kern County, California. Pilot area outlined by dashed line.

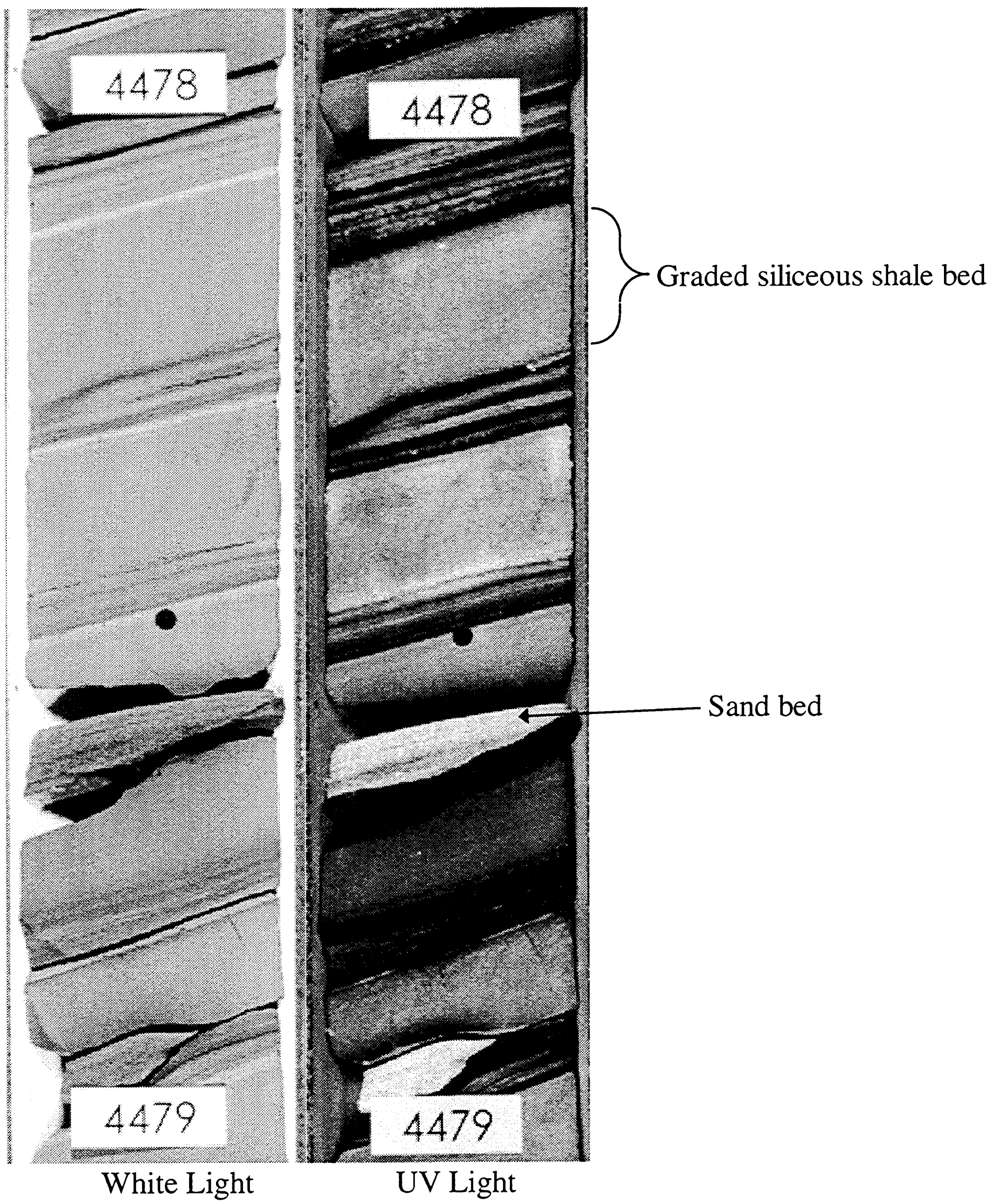


Figure 7. Core photos showing graded siliceous shale beds and interbedded sand beds.

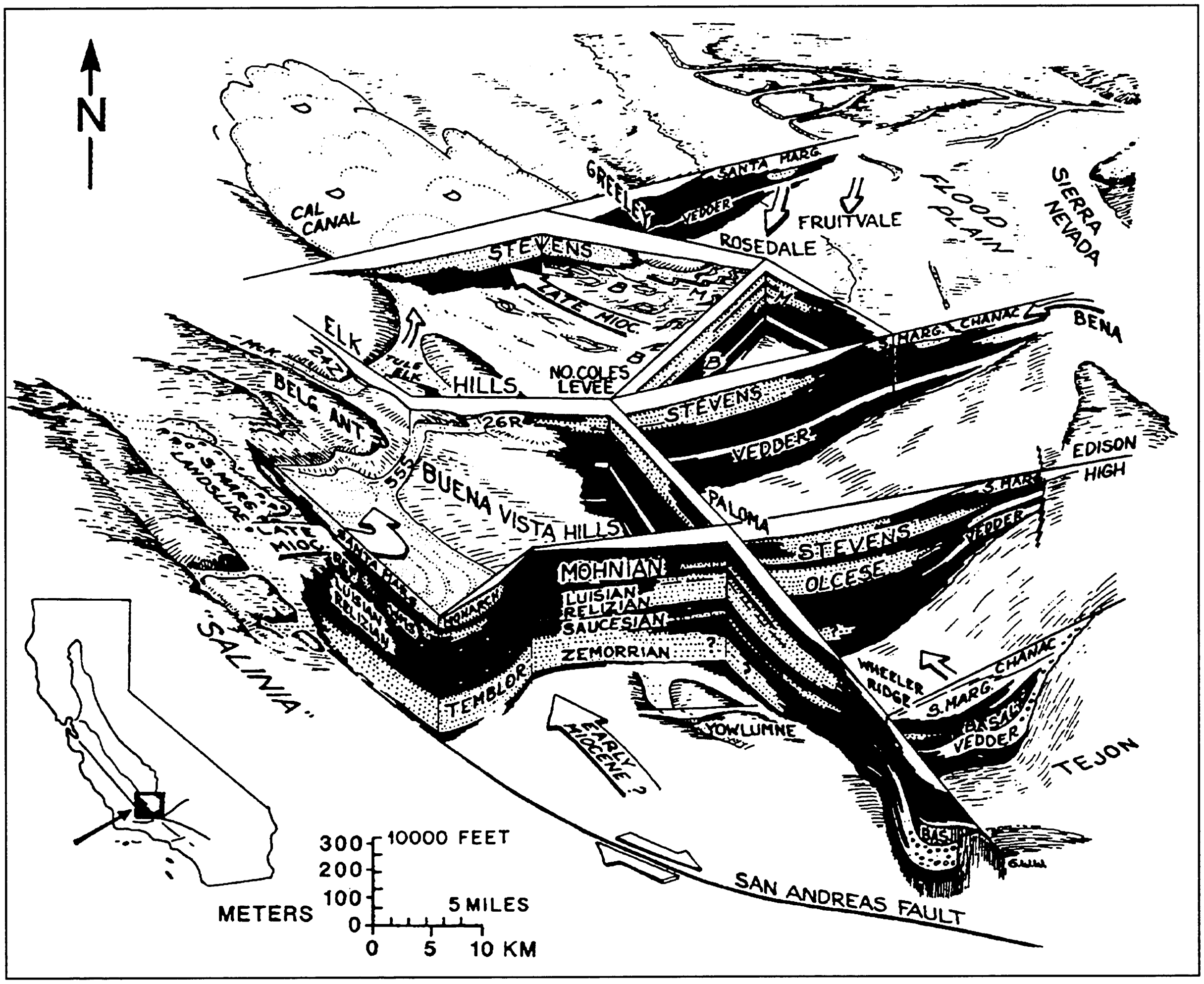


Figure 8. Diagram of depositional environment of the southern San Joaquin Valley in late Miocene time (from Webb, 1981)

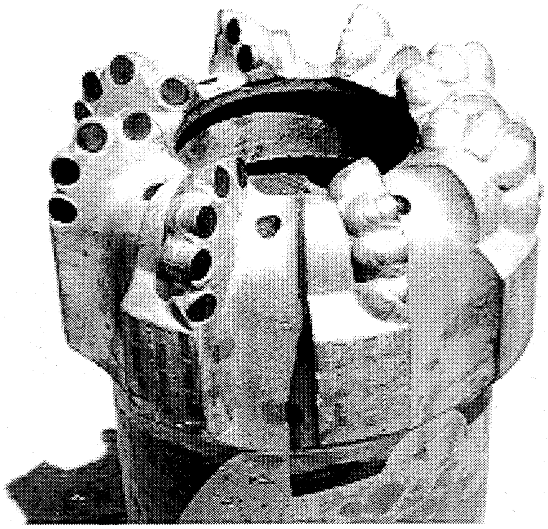


Figure 9. Baker-Hughes-Inteq core bit ARC-425 after coring the 653Z-26B well. Note face discharge ports, aggressive PDC cutters, and lack of appreciable wear. Throat is approximately 4-1/2 in. diameter.

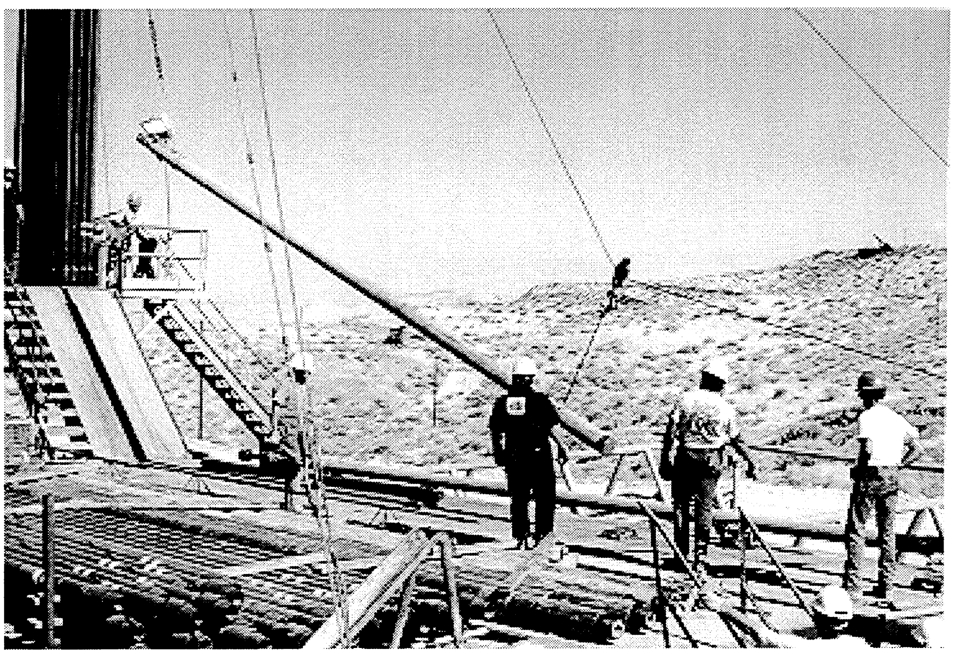


Figure 10. Lowering the core shuttle to the catwalk.

Figure 11. Core recovery table used to mark and divide the fiberglass inner barrel.

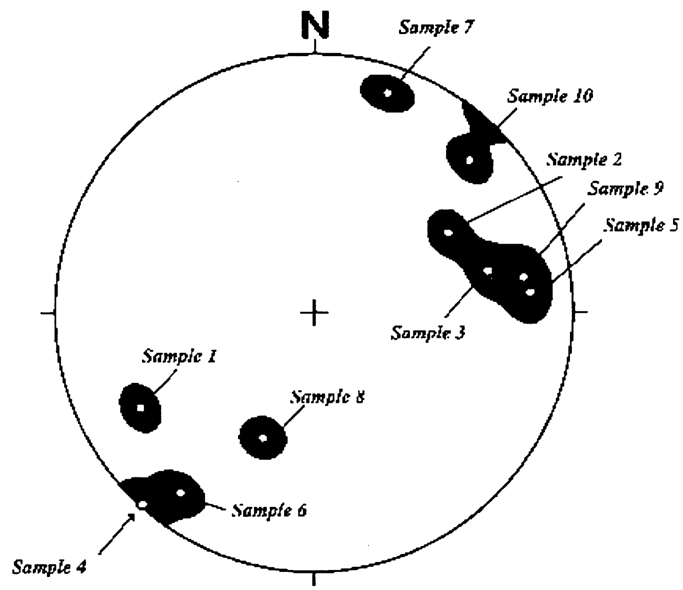


Figure 12. Stereographic projection (lower hemisphere) of the maximum principal stress axes. Note that most of the axes are subhorizontal and trend NE-SW. Scatter is due to inhomogeneity and variation with depth. Sample numbers match those in Table 2.

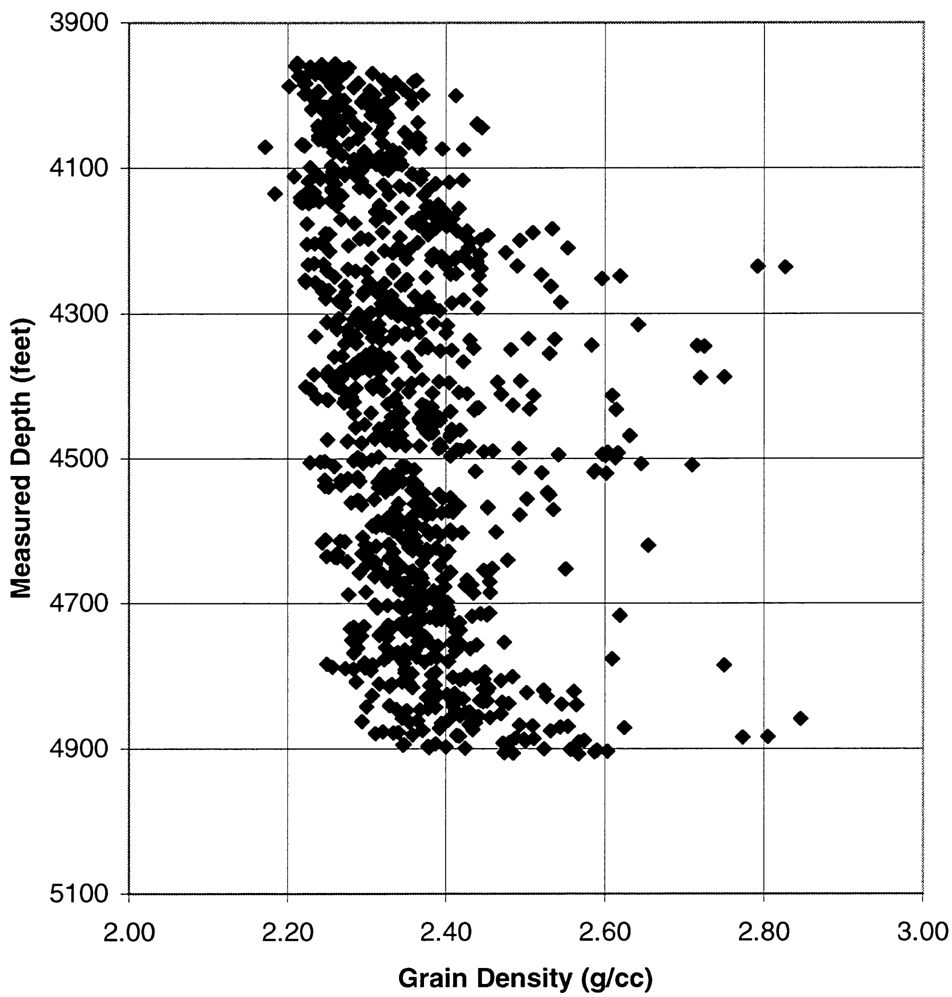


Figure 13. Matrix density from core variation with depth, well 653Z-26B, Buena Vista Hills field, Kern County, California.

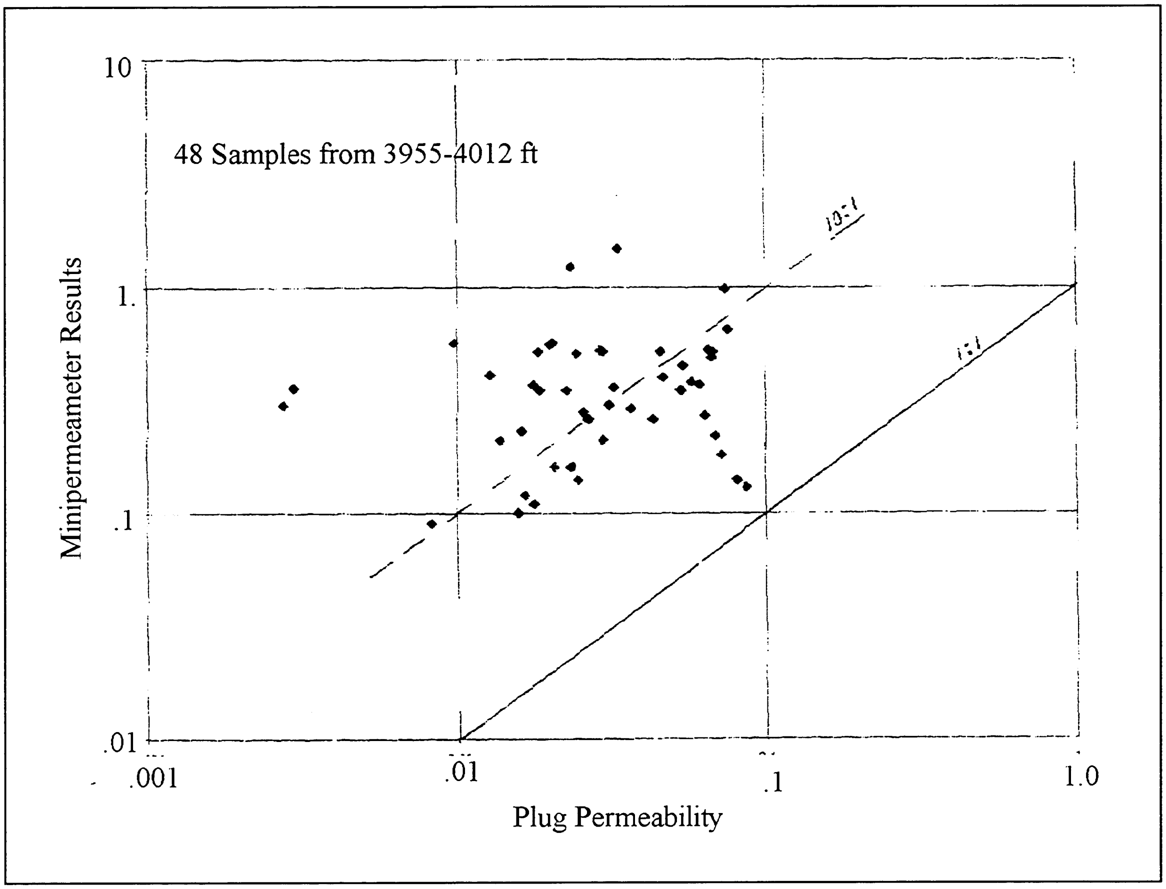


Figure 14. Comparison of core plug and profile permeameter results. The profile permeameter appears to measure permeabilities about ten times higher than equivalent core plug air permeabilities.

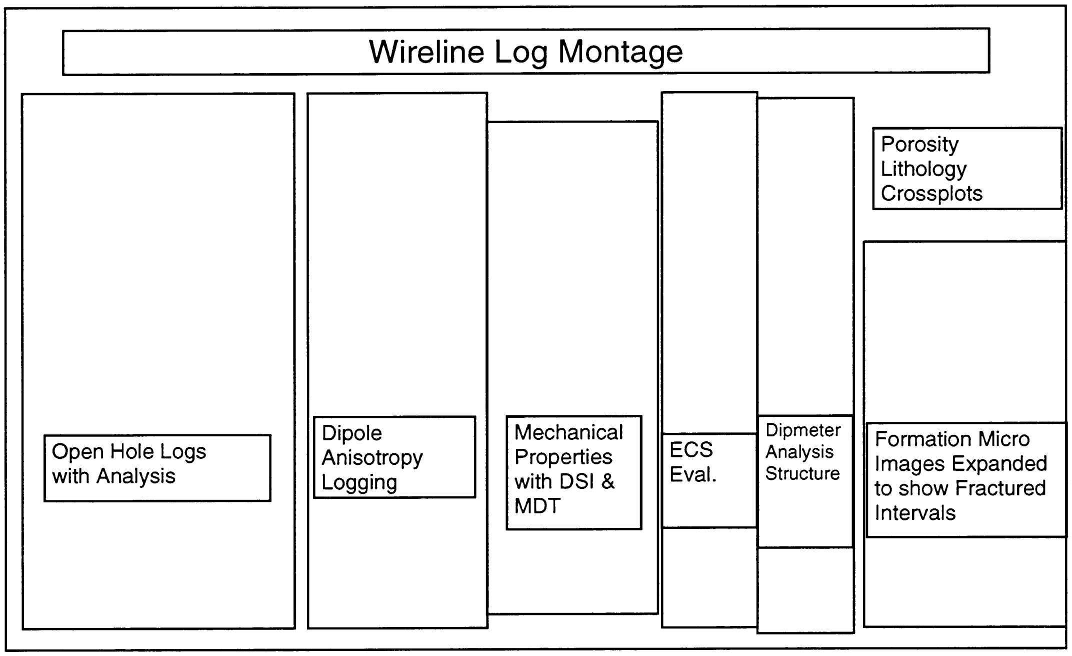
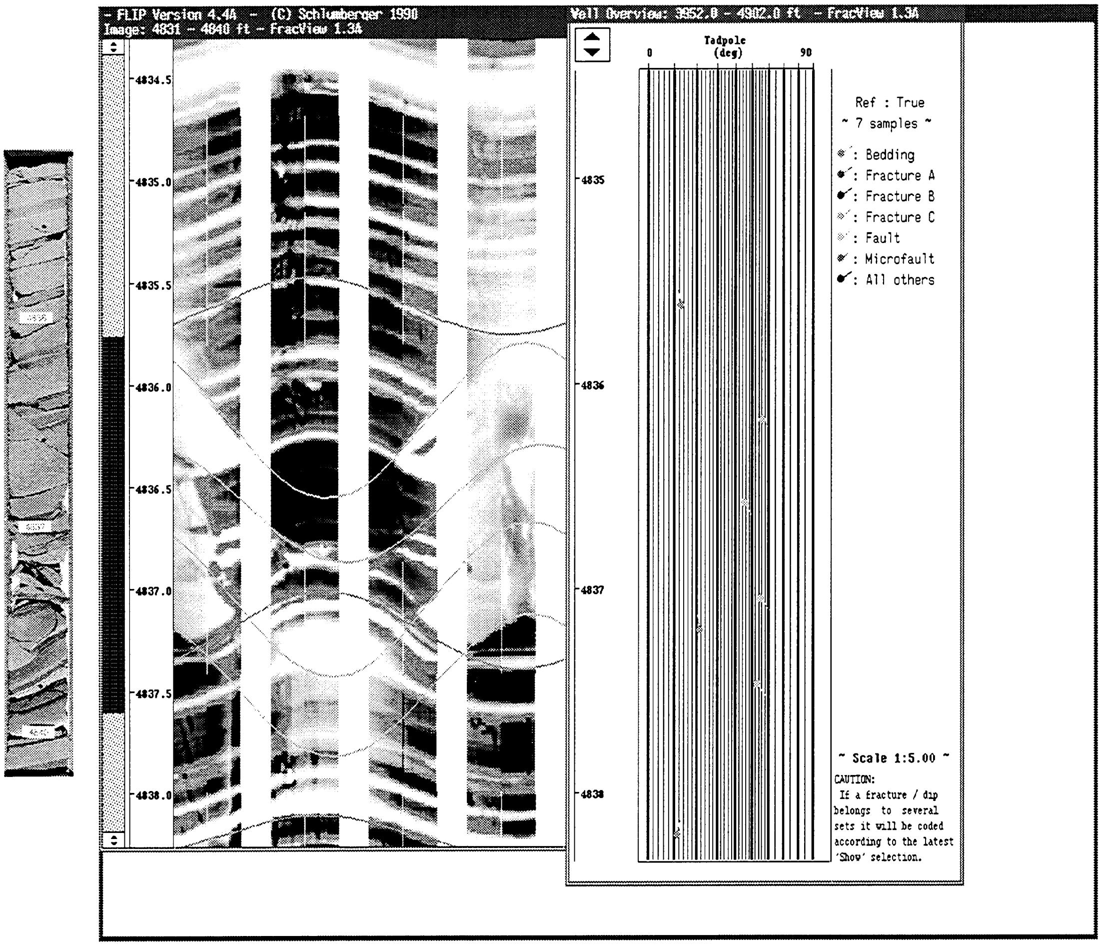


Figure 15. Schlumberger Wireline Log Montage, Chevron USA Inc. 653Z-26B, Buena Vista Hills Field.



(a) (b)

Figure 16. (a) Core photo in white light of equivalent depth interval in (b). (b) Formation MicroImager microresistivity image of lower Upper Antelope Shale.

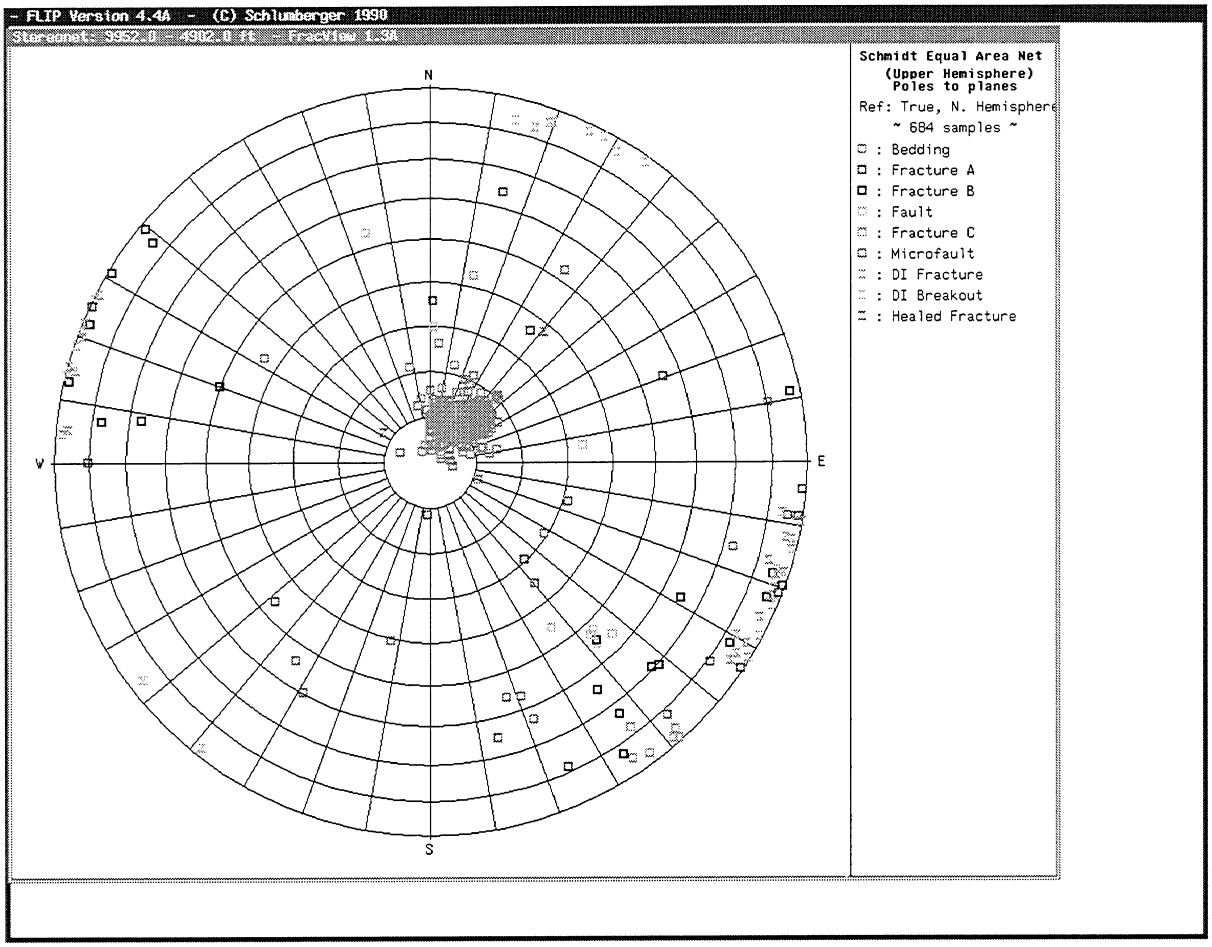


Figure 17. Upper hemisphere polar equal area net of poles to planes of bedding, faults and fractures.

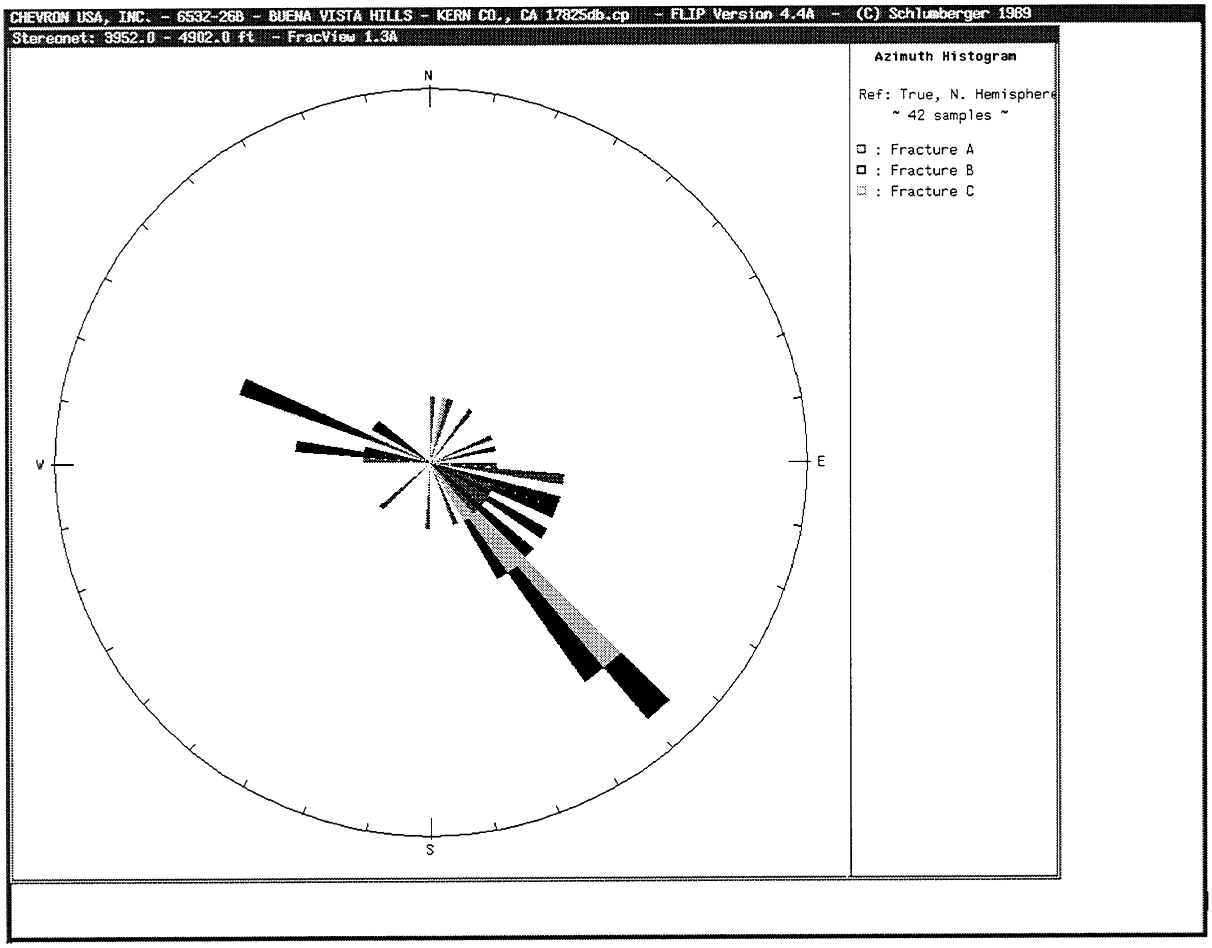


Figure 18. Histogram (rose diagram) of fracture dip azimuths interpreted from FMI.

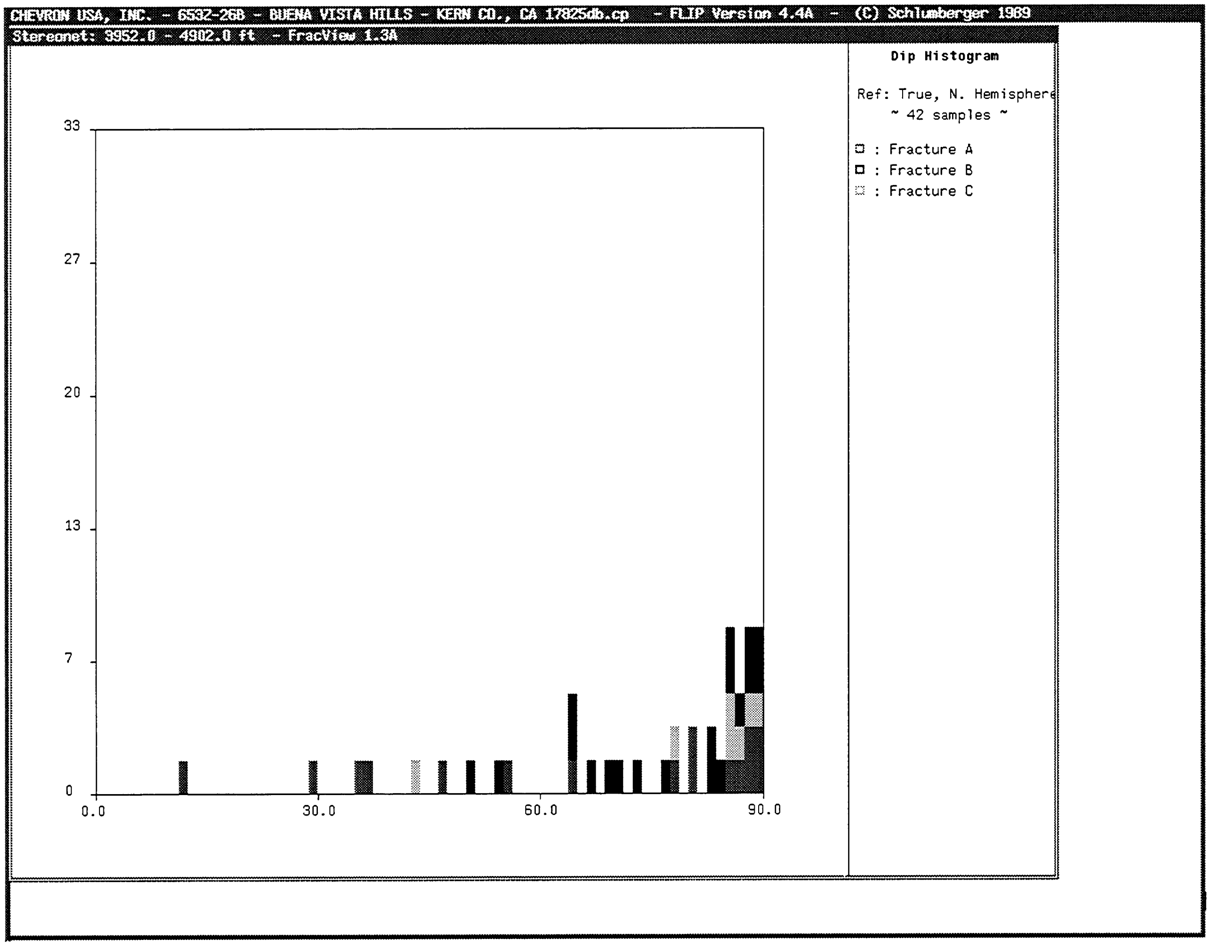


Figure 19. Histogram of dip magnitudes interpreted from FMI.

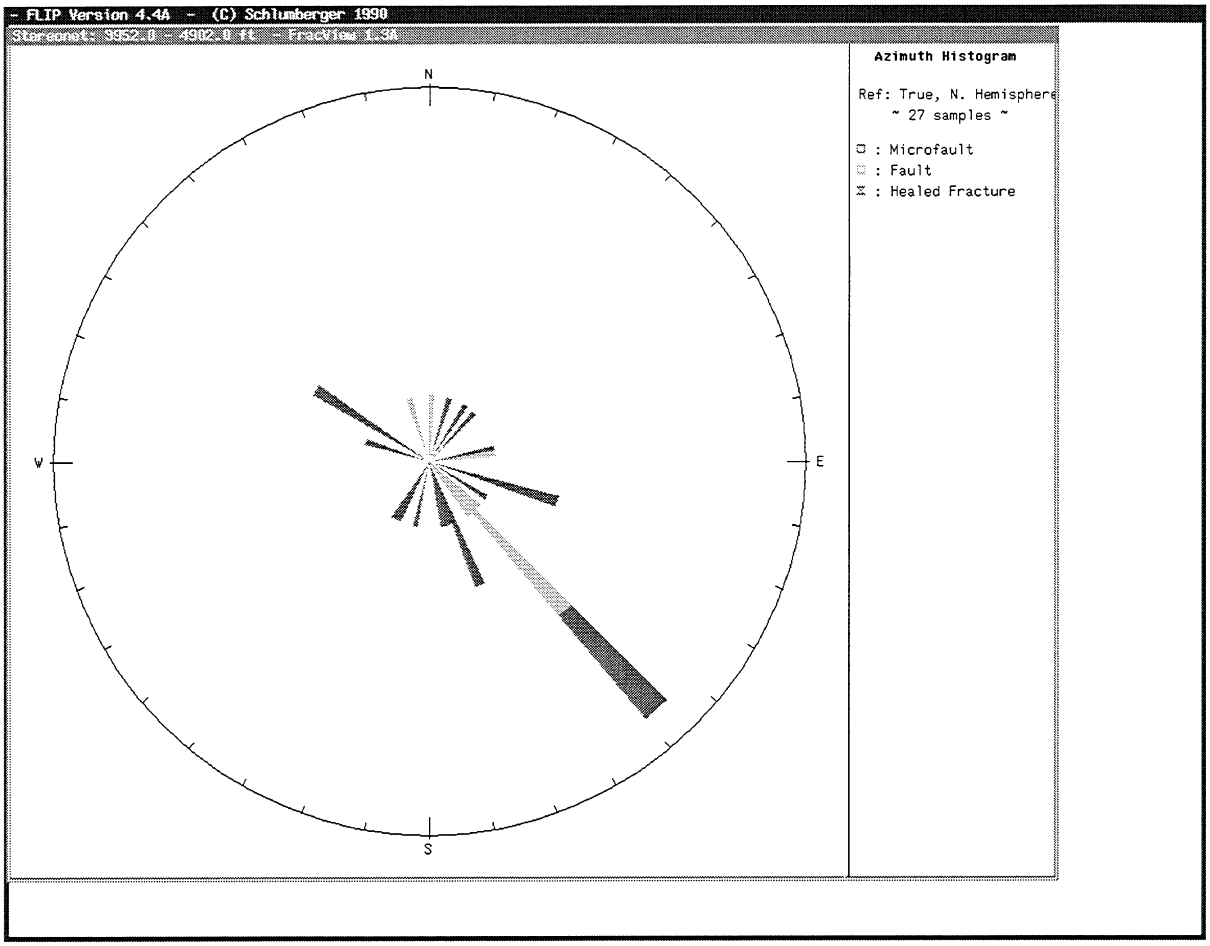


Figure 20. Histogram (rose diagram) of fault and healed fracture azimuths interpreted from FMI.

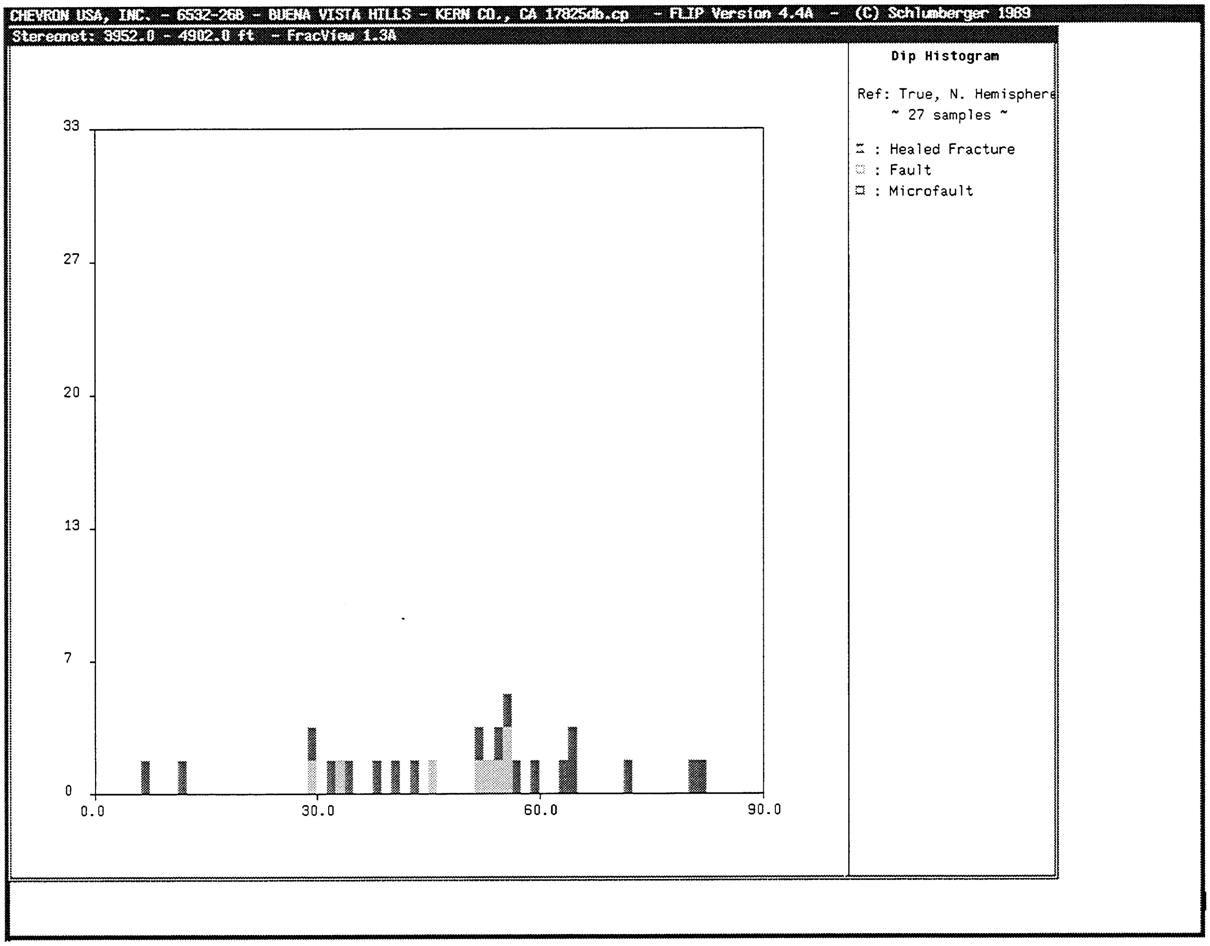


Figure 21. Histogram of dip magnitudes of faults and healed fractures interpreted from FMI.

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Bilodeau, B. J., 1997, Comprehensive reservoir characterization using open-hole wireline logs, core, and downhole video, Buena Vista Hills field, California. Accepted for presentation in the AAPG Pacific Section Convention, Bakersfield, California, May 1997.

Britton, A. W., Smith, J. L., and Chapman, D., 1997, Continuous permeability and porosity determination in the Chevron 653Z-26B well, Buena Vista Hills field, Kern County, CA. Accepted for presentation in the AAPG Pacific Section Convention, Bakersfield, California, May 1997.

Decker, D. J., and Bilodeau, B. J., 1997, Antrim Shale resource and reservoir characterization as an analog for diffusion controlled gas production from the Monterey Formation. Accepted for presentation in the AAPG Pacific Section Convention, Bakersfield, California, May 1997.

Dholakia, S. K., 1995, An integrative study of fractures and in situ stress in the Antelope Shale, Monterey Formation. Stanford Rock Fracture Project, v. 6, p. G-1 - G-9.

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